AL.2.2000-48
c.2
v.2

EUB

1999/2000 Electric Tariff Applications

ATCO Electric Ltd.
EPCOR Generation Inc.
EPCOR Transmission Inc.
TransAlta Utilities Corporation

Volume 2

Alberta Energy and Utilities Board

Digitized by the Internet Archive
in 2015

https://archive.org/details/19992000electric02albe

1999/2000 ELECTRIC TARIFF APPLICATIONS

VOLUME 1

Page

Part 1 – GENERAL 1

VOLUME 2

Part 2 – ATCO ELECTRIC LTD. 385
Part 3 – EPCOR GENERATION INC./EPCOR TRANSMISSION INC. 413
Part 4 – TRANSALTA UTILITIES CORPORATION 607
APPENDICES 821
PARTIES PARTICIPATING IN THE PROCEEDING 853
REFERENCES 857
ABBREVIATIONS 861

Files: AE 1108-1 / EPGI/EPTI 1703-1 / TAU 1207-1

VOLUME 2

Part 2 – AE

1. NEGOTIATED SETTLEMENT 387

2. RESERVE FOR INJURIES AND DAMAGES 388

3. QUALITY OF SERVICE 406

4. REGULATED AND UNREGULATED ACTIVITIES 407

5. SUMMARY OF BOARD DIRECTIONS 408

6. ORDER 411

Part 3 – EPGI/EPTI

1. GENERAL **415**

(a) Accounting Practices **415**

(b) Allocation of Common Costs **416**

(c) Incentive Compensation **420**

(d) Self-Insurance Reserve **429**

(e) Hearing Cost Reserve **430**

(f) Y2K **432**

(g) Return on Decommissioning Reserve **433**

(h) Inflation Assumptions **442**

2. EPGI **444**

(a) Rate Base **444**

(1) Capital Additions 444
(A) Historical vs. Forecast Capital Expenditures Levels 444
(B) Mine Related Capital Expenditures 448
(C) Clover Bar Capital Expenditures 451
(D) Genesee Black Start and Clover Bar Black Stop Projects 455
(E) Rossdale Decommissioning Costs 459
(F) Projects of less than $1.0 million 461
(G) 1992 Clover Bar IP Rotor Replacement and 1993 Insurance Claim 462
(H) Summary of Capital Additions 468

(2) Necessary Working Capital 469
(A) Operating Expenses 469
(B) Dividend Payment 472
(C) Inventory Valuation at 31 December 2000 473
(D) Remaining Items 473

(b) Minimum Return Margin **474**

(c) Cash Operating Expense **481**

(1) Dragline Operating Benefits 481
(A) The Board's Jurisdiction 482
(B) Relevance of the Boyd Report 492
(C) Value of the Operating Benefit 500

(2) Fixed Fuel Cost 504

(3) Variable Fuel Cost 507
(A) Coal Costs 507

(i) The Agreement between EPGI and Fording Coal Limited 508
(ii) Variable Coal Costs 515
(B) Variable Natural Gas Costs 519
(4) Operating and Maintenance 519
(A) Fixed and Variable Production 521
(B) Maintenance and Repair 525
(C) Generation Administration 535
(D) Corporate Services 538
(E) Summary 539
(5) Taxes Other Than Income Tax 540
(d) Depreciation 541
(1) Rossdale Decommissioning Costs 541
(A) Effect of the GUR on the Board's Ability to Modify Depreciation 541
(B) Effect of the GUR on the Mid-Year Depreciation Convention 548
(C) Prudence of Applied For Cost Increases 550
(D) Rossdale Decommissioning Allowed for 1999 and 2000 562
(2) Technical Update 568
(A) The Redistribution of Depreciation Reserves 572
(B) The 5% Threshold for Amortizing Reserve Imbalances 575
(C) The Segregation of the Decommissioning Reserve 578
(D) The Use of the Technical Update for Depreciation Rates 580
(E) Summary of Board Findings 583
(e) Reservation Price–Normalization Costs 583
3. EPTI 588
(a) Necessary Working Capital 588
(b) Cash Operating Expense 590
(1) Operating and Maintenance 590
(2) Taxes Other Than Income Tax 593
(c) Depreciation 595
4. SUMMARY OF BOARD DIRECTIONS 599
5. ORDER 604

Part 4 – TAU

1. GENERAL 609

(a) Software Development Additions 609

(1) Software Development (Undefined and Year 2000 Projects) 609

(2) Industrial Customer Billing System 611

(3) SAP Net Pay Module 611

(4) Customer Billing System 612

(5) Amortization Period 614

(b) Corporate Capital Additions 615

(1) Information Technology Hardware 615

(2) Calgary Head Office 617

(3) Sale of High River Service Centre 622

(4) Sustainable Development 629

(5) SD Projects 631

(6) Automated Mapping/Facilities Management 633

(c) Corporate Operating Expense 635

(1) Labor and Materials Escalation 635

(2) Telecommunication Expense 635

(d) Allocation of Common Costs 638

(e) Incentive Compensation 642

(f) Income Tax 644

(1) Income Tax Methods 644

(2) Currently Approved Method 646

(3) TransAlta's Proposed Method 647

(g) Hearing Cost Reserve 651

(h) Pension Reserve 653

(i) Self-Insurance Reserve 664

(j) Depreciation 672

2. GENCO 676

(a) Rate Base 676

(1) Capital Additions 676

(A) Capital Project Justification 678

(B) Highvale Ash Hauler Replacement 679
(C) Highvale Coal Hauler Replacement 681
(D) Highvale Pit 2 Drainage Ditch 683
(E) Sundance 1-4 Secondary Crusher Upgrade 683
(F) Brazeau 2 Generator Stator Rewind 685
(G) Wabamun 4 Mill Refurbishment 685
(H) Sundance Water Treatment Plant Replacement 686
(I) Feedwater Heater Replacements 687
(J) Sheerness Capital 689
(K) Highvale Mine Shop 689
(L) Highvale Pit 2 County Landfill Move 691
(M) Freehold Royalty Deferral 692
(N) Spray Woodstave Pipeline Replacement 693
(O) Hydro Maintenance Services Shop 694
(P) Bighorn Compensating Water Facilities 694
(Q) Wabamun Boiler Asbestos Removal 696
(R) Wabamun 4 Waterwall Replacement 697
(S) Sundance Generation Spare LP Rotor Purchase 698
(T) Sundance 2 Boiler Control Replacement 698
(U) Sundance 3 Boiler Control Replacement 699
(V) Keephills—Raise Primary and Secondary Ash Lagoon Dykes 699
(W) Total Generation Capital Additions 700
(2) Necessary Working Capital 705

(b) Cash Operating Expense 708

(1) Fuel Cost 708
(A) Escalation 709
(B) Strip Ratios 711
(C) Coal Hauler Savings 712
(D) Hauling Distance 714
(E) Non-Government Royalties 715
(2) Operating and Maintenance 716
(A) TransAlta's Thermal Units Operating and Maintenance 717
(B) Hydro Operating and Maintenance 720
(C) Generation Management and Administration 721
(D) Labor and Material Escalation 722
(3) Taxes Other Than Income Tax 723

(c) Non-Cash Operating Expense 725

(1) Amortization of Coal Costs 725
(A) Excess Outside Coal 725
(B) Excess Highvale Coal (Westmin 82 Agreement) 739
(C) Westmin 82 Take-or-Pay (1999 and 2000) 744

(D) Coal Reclamation Costs 748
(d) Income Tax 756
(e) Small Power Payments 757
(1) Revenue Adjustment 758
(2) Excess Energy Cost 766

3. TRANSCO 770
(a) Necessary Working Capital 770
(b) Cash Operating Expense 772
(1) Operating and Maintenance 772
(A) Labour–Duplication of Planning Costs 772
(B) Gross Labour Escalation 772
(2) Taxes Other Than Income Tax 772
(c) Income Tax 773

4. DISCO 774
(a) Rate Base 774
(1) Capital Additions 774
(A) Generic Capital Additions Adjustment 775
(B) Oilfield Metering Installation Project 776
(C) Purchases of REAs 779
(D) Distribution Customers 784
(E) Remaining DISCO Capital Projects 785
(2) Line Twinning 787
(3) Necessary Working Capital 790
(b) Cash Operating Expense 792
(1) General 792
(2) Labor and Materials Escalation 793
(3) Advertising and Marketing 794
(4) Bad Debt Expense 796
(5) Taxes other than Income 798
(6) Cash Operating Expense Summary 800
(c) Income Tax 800
(d) Quality of Service 801
(e) Revenues 804
(1) Energy Sales and Revenues 804

(2) Unbilled Revenue 807

(f) Revenue Surplus/Deficiency 808

(g) Customer Deposits 809

5. SUMMARY OF BOARD DIRECTIONS 812

6. ORDER 820

Part 2 – AE

1. NEGOTIATED SETTLEMENT

On 22 April 1999 the Board received an application from Alberta Power Limited (APL) to approve a negotiated settlement agreement (Settlement) that they had reached with interested parties on most aspects of its 1999/2000 Phase I General Tariff Application. On 6 May 1999, APL notified the Board that its name has been changed to ATCO Electric Ltd. (AE). Therefore, the Settlement application and the GTA will be considered to have been filed by AE. The matters that were not covered by the Settlement were:

- The generation portion of the reserve for injuries and damages as of 31 December 2000.
- The Terms and Conditions of service, pursuant to which AE's generating units provide ancillary services.
- Matters relating to the roles and responsibilities of the TA and the Terms and Conditions of transmission wire service.
- The treatment of transmission capital additions including the circumstances and criteria used to determine when and if the TA or the TFO should be responsible for such projects.

The Board issued Decision U99046, dated 10 May 1999 approving AE's Settlement, the rates arising from it and AE's revenue requirement for 1999 and 2000. The distribution revenue requirement approved for 1999 and 2000 were $553,600,000 and $549,100,000 respectively. The matters not covered by the Settlement were examined during the hearing and will be dealt with in this Decision. The Board will not be making any further determinations with respect to AE on those matters covered by Decision U99046. The Board notes however that the Settlement allowed for adjustments to the rates and revenue requirements approved by Decision U99046 pending the Board's resolution on the outstanding items, as required.

Part 2 - AE

2. RESERVE FOR INJURIES AND DAMAGES

AE did not reach agreement in its negotiated settlement on the amount to be included in the generation portion of its Reserve for Injuries and Damages (Reserve). AE proposed that its Reserve should continue through 1999 and 2000. The following table indicates the amounts that AE forecast for the generation portion of its reserve for injuries and damages for 1999 and 2000 in comparison to the years 1996 through 1998.

	($000)				
	1996 Actuals	**1997 Actuals**	**1998 Forecast**	**1999 Forecast**	**2000 Forecast**
Opening Balance	971	117	-3581	-18976	-16984
Annual Provision	1005	1005	1005	1005	1005
Additional Provision	0	0	0	1805	1805
Expenses	-1859	-4703	-16400	-818	-818
Closing Balance	117	-3581	-18976	-16984	-14992

Reference: AE Application, Volume II, Tab Cash Operating Expenses, Schedule 5.23

The Reserve is used to fund potential claims that are not otherwise insured. In Decision U97065 the following described AE's position on the criterion to define losses to be charged to the Reserve.

> APL established two criteria to define these losses. The first criterion included uninsured and uninsurable losses resulting from design error, failure to supply (blackouts, brown-outs), professional and pollution liability. The second criterion applied to the deductible portion of insured losses, including any portion of the loss not covered by insurance policies and any extra portion related to plant outages.[1]

There were a number of large claims in 1996, 1997 and 1998 respecting the H.R. Milner plant and the Battle River 4 unit. AE proposed to continue its annual provision of $1.005 million to the Reserve and to amortize the 1998 year-end deficiency over a ten-year period that results in a further expense of $1.805 million in 1999 and 2000. It is AE's position that, if the IAT does not

[1] Decision U97065, p.324

provide for recovery of the remaining amount to be amortized through the PPAs, AE intends to revise its application to seek full recovery of the unamortized portion by the end of 2000.

The total claims made against the Reserve in 1996, 1997 and 1998 are summarized below.

Claims against AE's Reserve for Injuries and Damages				
	1996	1997	1998	Total (1996-1998)
Total $000's Claimed	$1,859	$4,703	$16,400	$22,962
# of Incidents	17	4	25	46

Reference: MI.APL-43(a)

AE uses the Reserve differently than either TransAlta or EPGI. TransAlta does not include the cost of generation outages in its reserve. EPGI does not draw on the Reserve as a means of covering a generator's UOV payments, lost surplus revenue or maintenance expenses. The EPGI reserve is used only in respect of the insurance policy deductibles.

Position of ENMAX

ENMAX noted that AE is seeking to recover claims made in the 1997/1998 period against the Reserve. ENMAX identified the following as its concerns with the Reserve:

- How the reserve, risk and TSR are related.
- The basis of claiming against the Reserve.
- The differences among the Utilities respecting the Reserve and self-insurance.
- The opportunity to mitigate damages and how they are reflected in the Reserve.

ENMAX stated that it is AE's claims for business interruption arising from property damage that it considered to be the more controversial of AE's claims. ENMAX noted AE's approach that, in order to qualify as a claim against the Reserve, the event must be a sudden or accidental insurable event with a low probability of occurrence. Claims that qualify under the deductible component of the property insurance policy generally cause little controversy except where there are questions whether or not the costs ought to be recoverable from a third party such as the original equipment manufacturer.

ENMAX noted that AE did not apply for TSR for either of its major business interruptions at H.R. Milner or at Battle River 4 as it did not consider the risks to be outside of that which it is compensated to accept. AE's position was that it should not have to file for a TSR to recover the deductible portion of insured losses. AE looked to the Reserve first and then to the TSR. ENMAX questioned whether this was reasonable when considering business interruption coverage. ENMAX suggested that the TSR was designed to cover significant business interruptions. ENMAX stated its concern that there is no clear distinction or objective criteria to

determine between events which are "normal", events which should be charged to the Reserve, and those events which should face a more rigorous test under the TSR.

ENMAX stated that making a claim against the Reserve is a very open-ended risk mitigation process, as there appears to be no threshold amount to be eligible, no quantification of probability of occurrence, and no quantification of a "significant" outage. ENMAX noted that, where insurance is in place, insurers would have sufficient self-interest to police claims that exceed the deductible amounts. However, where the event is insurable but insurance is not in place, or for claims such as business interruptions of less than 60 or 90 days the scrutiny is minimal. If there were no Reserve for business interruption, AE would be required to pursue claims through the TSR. This would lead to a formal process with criteria for qualifying and appropriate public scrutiny. The level of risk which a generating utility is compensated to accept would be reviewed in such a process. ENMAX submitted that AE should be required to pursue all attempts at mitigating claims by filing against appropriate third parties.

ENMAX noted that TransAlta, EPGI and AE have taken different approaches to self-insurance. The lack of consistency is a concern to ENMAX as it does not allow for comparability of costs for similar services. ENMAX supported the establishment of consistent criteria for filing claims against the Reserve. Those criteria should fully consider the amount of risk the generating utility is compensated to assume through the approved return on equity as well as the purpose and intent of the TSR. Additional compensation for the risk of generation outages should not be a matter for the Reserve.

ENMAX submitted that, for claims associated with property damage deductibles, the parties should pursue accountability from equipment manufacturers and contractors before charging claims against the Reserve. For claims relating to business interruption it is necessary to pursue any available third parties and also to consider and account for the potential of positive impacts which may follow. ENMAX noted AE's acknowledgement that one of the results of a unit failure can be increased pool prices. H.R. Milner is normally the last coal unit dispatched before gas units come on. At times, 140 MW of additional supply or unavailable supply can influence pool price. ENMAX stated that AE has never calculated or credited any amounts to the Reserve for higher pool prices that may result from a unit outage. It would appear that there are some offsets to the cost of these outages, in terms of potential benefits that AE may be receiving from its units therefore AE should be required to deduct any benefits before charging all costs to the Reserve. ENMAX further noted that AE appeared to be charging the Reserve for outages longer than the forecast forced outages of each unit but not crediting the Reserve for saved days when forecast planned maintenance is done during forced outages. For example, when H.R. Milner was forced out for 53 days longer than forecast in 1997, it also resulted in reduced planned outages of 26 days, or half of the outage claim. ENMAX recommended that, at a minimum, this amount should be credited to the Reserve.

ENMAX submitted that AE has not proven that self-insurance is the most cost effective option to provide insurance coverage in 1999/2000. ENMAX also submitted that AE's claims should not

be accepted. ENMAX recommended that a threshold level similar to TransAlta's should be applied. Also, claims such as the cracked rotor, turbine shrouds and other equipment failures should be held in abeyance until legal remedies are exhausted. There must be recognition that AE's outages will be mitigated by higher pool prices and saved planned maintenance costs. ENMAX considered that remaining claims for generation outages should be the subject of TSR treatment at the time of the extended outage being incurred. Customers should not be required to provide additional compensation through the Reserve and shareholders should absorb the cost of individual generation outage claims.

Position of the FIRM Customers

The FIRM Customers submitted that, given AE's treatment of its Reserve as compared to the other Utilities, AE's risk appears to be substantially reduced relative to the other Utilities even recognizing that AE removes outages related to reserve claims from its generation modeling statistics.

The FIRM Customers noted the criteria for claims to the Reserve established by AE and that there have been two changes to the policy from the time of AE's 1996 GTA. The AE policy of not insuring for loss of generation not lasting less than 90 days has been shortened to 60 days. Also, AE now takes the position that UOV payments, required to be made during a generation outage fall within the definition of extra expenses defined in AE's criteria and should be paid from the Reserve.

The FIRM Customers submitted that it considered that coverage principles under self-insurance should follow those under commercial insurance. The consequences of all outages with a duration not exceeding the average number of days per outage event contemplated under the planning assumptions are implicitly mitigated by the risk allowances built into the planning assumptions. Therefore, self-insurance should only cover insurable events for the period in days greater than allowed in the planning assumptions for each event and before commercial insurance is activated after 60 days, to prevent double recovery. In other words, cost recovery for each business interruption loss resulting from sudden and accidental outages would be from four distinct sources. The first portion of the recovery for business interruption would be through the planning assumptions. The second portion of the recovery would be from the Reserve for those insurable events of greater duration outage than covered by the planning assumptions. The period covered by the planning assumptions would be the maximum number of days per outage duration reflected in the planning parameters. The third portion of the recovery for insurable events would be by way of commercial insurance for periods after the 60 day waiting period. The fourth means of recovery would be through the TSR for events neither insurable nor otherwise eligible for a claim against the Reserve. The FIRM Customers noted that the information required to apply these principles to the 1996 to 1998 claims may not be on the record but recommended that AE be required to submit the information with respect to 1999 and 2000 in its refiling. In particular, the maximum number of days per outage reflected in the generation modeling assumptions should be determined from a review of the distribution of forced and maintenance outage duration per event. Any outage duration per event with at least a

95% chance of occurrence would be part of the planning assumptions. For example, in a distribution of outage duration per outage event, if 20 days per event were at the 95% confidence limit, 20 days would become the threshold number of days above which claims would be made to the Reserve.

The FIRM Customers submitted that AE inappropriately uses the Reserve by charging UOV payments against the Reserve. The FIRM Customers noted that the Board, in Decision U97065, specifically stated that the Reserve should not include costs resulting from industry restructuring under the EU Act. The FIRM Customers suggested that claims not eligible for the Reserve might require an application pursuant to the TSR. The FIRM Customers submitted that the outages in question fall within the qualifying provision of section 5(1)(a) of the TSR and it is incorrect for AE to request customers to compensate it for a cost that may have been avoided through an application under the TSR.

The FIRM Customers further noted that AE still has the opportunity to file an application with respect to suspending UOV payments for claims during the 1996 to 1998 period pursuant to the TSR. Therefore, the FIRM Customers submitted that any Board adjustments should not preclude this possibility for dealing with these claims.

The FIRM Customers raised the question of whether AE received offsetting benefits from higher pool prices during the outages at H.R. Milner and Battle River 4. The FIRM Customers noted that the Power Pool of Alberta indicated in both its March and April 1998 monthly reports that scheduled and unscheduled outages caused higher pool prices. The FIRM Customers also noted that another indicator of the variability of pool prices due to load/supply balance is found in each of the Utilities' filings, in their response to the Board's direction for each Utility to file pool price sensitivities for +/- 1.5% variance in system load forecasts. Based on 2000 pool prices which are closer to 1998 pool prices, a 1.5% increase in load is estimated to result in an increase of pool price of $2.52 to $2.70 per MWh. A 1.5% load reduction is estimated to reduce pool prices by $2.19 or $2.20 per MWh. The FIRM Customers submitted that, on this basis, a 290 MW loss of coal fired capacity could, in theory, result in a $6 or $7 per MWh change in pool price, which is not unlike the $6.57 per MWh from February to March 1998 as shown in the Power Pool monthly reports. The FIRM Customers acknowledged that a 110 MW change in load would not necessarily result in the same pool price change as a 110 MW loss of capacity but noted that each successive 100 MW block would have an exponentially greater impact on pool price. Therefore the FIRM Customers suggested that AE's estimate of less than a $1 per MWh impact due to the unscheduled and coincident outages of Milner and Battle River 4 during March and April 1998 is understated. The FIRM Customers recommended that the pool price for AE's other generating units should be increased by $6 per MWh from March to mid-April and $3 per MWh from mid-April to 30 June 1998. The FIRM Customers stated that this would translate to increased receipts at other AE units of $1.1 million and submitted that these amounts should be removed from the claims against the Reserve along with the 43.5% tax impact. The FIRM Customers noted that if AE can demonstrate that there is no material change in pool price by way of modeling, the FIRM Customers would be satisfied that no offset is required.

2. RESERVE FOR INJURIES AND DAMAGES

The FIRM Customers stated that an extended forced outage provides an "opportunity" to perform planned maintenance during the forced outage. Therefore the planned outage may be reduced or eliminated as happened with H.R. Milner in 1998. The FIRM Customers submitted that as a result of the prolonged forced outage at H.R. Milner commencing on 3 March 1998, AE was able to eliminate the 23 day planned outage.

The FIRM Customers submitted that charges to the Reserve should not be considered in isolation. The FIRM Customers noted AE's statement that it was inappropriate to look at any of the planned outages because there was nothing identified in the negotiated settlements. The FIRM Customers stated that all direct and indirect impacts of charges against the Reserve should be considered relevant in this proceeding. The FIRM Customers considered that AE received approximately $2.45 million of additional pool receipts or additional revenues as a direct result of the planned outage "opportunities" which resulted from claims against the Reserve. The FIRM Customers submitted that this amount should be offset against AE's claims against the Reserve during the period 1996 to 1998. The $2.03 million of shortfall related to the forced outages (shown in Exhibit 186) should not be offset against the $2.45 million related to the planned outages as the $2.03 million goes beyond what AE has defined as its business interruption or extra expense provisions, being the UOV payments. The FIRM Customers noted that the $2.45 million should also be grossed up for taxes.

The FIRM Customers noted that AE repaired a cracked rotor on the H.R. Milner unit during 1998 that resulted in a claim of $6.68 million against the Reserve - $5.06 million for UOV payments and $1.62 million for capital costs. This event was not insurable and was specifically excluded from the policy. The FIRM Customers noted AE's position that this claim should be covered by the Reserve because it was an uninsured loss, an insurable event but an uninsured loss and it was potentially insurable because it was a sudden and accidental claim. The FIRM Customers disagreed as the occurrence was excluded by the insurance policy and did not arise as a result of any of the factors listed in AE's criteria. The FIRM Customers stated that this was not a sudden and accidental breakdown of the rotor. The FIRM Customers noted that the rotor was 25 years old and the cracking was detected during other repairs to the unit. The FIRM Customers suggested that this claim against the Reserve is a capital maintenance project. The FIRM Customers stated that maintenance expenditures are normal recurring costs and, in this case, the rotor simply required maintenance after 25 years. Therefore the FIRM Customers recommended that the $1.62 million of capital costs be treated as a capital maintenance item and that the $5.06 million of UOV payments be removed from the Reserve. Failing this, the FIRM Customers submitted that this claim should be dealt with by an application pursuant to the TSR.

The FIRM Customers noted that AE repaired damaged turbine blades and shrouding at H.R. Milner during the 6 October 1997 outage and that the same turbine blades and shrouding had to be repaired 2½ months later in the 3 March 1998 outage. AE concluded that there was little chance of recovery from Hitachi. AE indicated that the cause of the failures was attributable to a condition in the machine caused by harmonic vibration that arose due to subtle changes in the

machine over the years. The FIRM Customers suggested that this could be a case where AE or its agents failed to recognize the harmonic vibration problem in a timely manner or AE was reluctant to pursue its claim. The FIRM Customers submitted that, rather than absolve all parties of blame and charge the customers, perhaps someone other than the customers should be accountable. The FIRM Customers submitted that AE should share a portion of the cost related to the second repairs and suggested that 50% is appropriate. Therefore, the FIRM Customers recommended that $1.37 million plus associated taxes should be removed from the H.R. Milner broken shrouding claim against the Reserve.

The FIRM Customers noted a similar situation with the turbine blades on the Rainbow 2 unit. The 13 April 1998 outage was caused by improper restoration of the turbine blades by a contractor in 1997.[2] The FIRM Customers noted that, although there was a warranty obligation by the contractor, AE seemed reluctant to pursue its remedies and only recovered $22,000 from the contractor whereas customers incurred costs of $766,000. The FIRM Customers suggested that this is not a fair sharing of responsibility between the owner and customers and suggested that a 50% sharing would be appropriate. Therefore, the FIRM Customers recommended that the Rainbow 2 damaged blades claim against the Reserve be reduced by $383,000 plus associated income taxes. The FIRM Customers noted that, during the hearing, AE stated that it would credit the Reserve for the five days of UOV payment that were covered by the policy with respect to the 6 October 1997 outage at H.R. Milner. This reflected AE's reduction in its waiting period from 90 days to 60 days that was changed in early 1997. The FIRM Customers estimated that this adjustment should be approximately $178,000 based on a simple prorating of the UOV payments down to 60 days.

The FIRM Customers noted AE's argument that absent the Reserve there would be a dramatic increase in insurance costs. The FIRM Customers noted that AE's actual and forecast total corporate insurance expenses for the years 1997 to 2000 compare to TransAlta's insurance costs as follows.

$millions	1997	1998	1999	2000
AE	2.1	2.1	3.0	3.2
TransAlta	3.5	3.8	6.7	6.9

The FIRM Customers noted that TransAlta's generation only insurance costs in 1999 and 2000 (without a reserve for injuries and damages) is forecast to be $5.6 million and $5.8 million. Therefore AE's forecast corporate insurance expense is about half of TransAlta's generation only insurance expense although AE has only about 1/3 of the generating capacity.

Position of IPCAA

IPCAA objected to AE using the Reserve to recover UOV payments related to generation outages. IPCAA submitted that AE's treatment of the Reserve for this purpose does not fit within

[2] ENMAX.AE-83

the original intent of the Reserve and imposes an unfair burden on customers. IPCAA stated that in the 1997 and 1998 negotiated settlements between AE and its customers, AE negotiated a deferral account related to the surplus/shortfall whereby 50% of any variance should be shared with customers. IPCAA asserted that, with this arrangement, AE makes a profit when charging UOV to the Reserve as any amount charged is refunded 50% to customers through the deferral account but would be recovered 100% from customers through amortization. IPCAA illustrated by noting AE's charge of $14 million to the Reserve in 1998 for the outage at H.R. Milner. This $14 million charge increased the surplus/shortfall by a commensurate amount of which customers would receive half. However, AE would then charge customers the full $14 million through the proposed amortization of the Reserve. IPCAA submitted that the greater the amount of UOV charged to the Reserve, the greater the profits to AE. IPCAA argued that this is contrary to the intent of sharing surplus/shortfall variances.

IPCAA also questioned whether the outage at H.R. Milner increased surpluses at other plants due to the effect on pool price. IPCAA submitted that the unavailability of 290 MW of capacity would have a very significant effect on pool prices. IPCAA noted TransAlta's testimony that the exclusion of the TransAlta Energy Marketing generating plant at the Sundance station, which has a capacity of 210 MW, would increase the calculated pool price by $3.82/MWh. Additionally, EPGI presented evidence that the better-than-expected availability of the Genesee plant in 1998 reduced the average pool price by an estimated $1.26/MWh which reflected a difference in capacity of an estimated 20 MW of capacity. IPCAA submitted that the outages at H.R. Milner and Battle River 4 would have had a material impact on pool price.

Position of AE

AE requested to include $1,005,000 for each of 1999 and 2000 in the generation portion of its Reserve to reflect a normal level of expected claims to the Reserve. AE also requested to include an additional provision of $1,805,000 in the Reserve for each of 1999 and 2000 to reflect the amortization of the balance in the generation Reserve over 10 years. This proposed treatment assumes that the IAT will allow AE to recover the remaining 8 years of amortization through approved PPAs. If this is not allowed by the IAT, AE proposed to amortize the full generation portion of the Reserve over 1999 and 2000. AE requested specific approval of this treatment if the IAT does not allow the amortization amounts that AE is proposing. AE also requested specific approval of the amounts charged to the Reserve up to the cutoff date for the filing of the Phase I Application (October 1998). AE clarified that it will be requesting a final "true up" to cover items charged to the Reserve from the time of filing the Phase I Application to the commencement of the PPAs.

AE stated that it has not changed its usage of the Reserve from previous GTAs and that the only change is the magnitude of the balance in the account. AE submitted that the magnitude of the balance should not affect the principles used in booking items to the Reserve nor the legitimacy of using this mechanism to seek appropriate and fair compensation for costs that are not otherwise covered. AE argued that denial of its requested claims against the Reserve would be unfair, as AE does not have any alternate approaches in place to allow for compensation of these

claims and AE would be exposed to significant risk from which it would not be protected. AE stated that the risk mitigation effect of the Reserve is factored into its allowed rates of return.

AE stated that it is not using the Reserve as a substitute for an Order under the TSR. An event is eligible for consideration under the TSR if it is beyond what the utility is compensated to accept. Therefore, AE submitted that the first hurdle in the process is to determine if an item fits into the criteria for the Reserve because if it does, AE is already compensated via this mechanism. Only if a determination is made that the item does not fit within the criteria for the Reserve, that it is considered under the TSR. AE noted that if is used the TSR treatment for the outages at Battle River 1 and 2 which was an example of an outage that was not due to a sudden and accidental event. AE submitted that its process is consistent with both Decision U97065 and the TSR. AE argued that it would be unfair to adopt a different interpretation and apply it retroactively when AE has acted in good faith in its reliance on this approach.

AE noted the following from the Board's determinations on the Reserve in Decision U97065:

> The Board considers that the reserve for injuries and damages ought to be used for the purposes intended and not to include costs resulting from industry restructuring under the EU Act.[3]

AE submitted that it has not included industry restructuring costs in the Reserve. AE noted that it has consistently used the Reserve to cover the costs associated with business interruptions that are not covered by its insurance policies. The insurance coverage held by AE includes a provision for "extra expense" to cover business interruption, subject to a 60 day deductible period. AE argued that the claims against the Reserve that included UOV payments reflected the quantification of business interruption costs associated with a particular event. AE submitted that these UOV payments relate to the operation of its generation units and cover the deductible portion of its "extra expense" insurance coverage. AE also submitted that, should a change to its policy be approved, it should only be done on a going forward basis effective upon the release of the Board's Decision. This will provide AE the opportunity to adopt alternate approaches to ensure that it is compensated for these events and allow AE the opportunity to recover for any events which may occur leading up to the Decision. In response to the FIRM Customers, AE stated that claiming UOV payments against the Reserve was not a new usage of the Reserve and emphasized that that the UOV payments are a method of quantifying business interruption costs in the current legislative environment.

AE questioned whether the concerns raised with respect to its claims against the Reserve related to the legitimacy of the claims or their magnitude. AE noted the random and variable nature of insurable events and stated that it could neither predict nor control these events. Absent an ability to claim these items to the Reserve, there would be an increase in AE's insurance costs.

[3] p.329

AE stated that it does not claim all lost UOV payments to the Reserve. AE noted that "normal" outages are not eligible candidates to have the UOV payment component of the overall costs associated with the event included in the Reserve. These outages have been included in AE's normal forecast outage statistics, which are reflected in modeling. These "normal" outage events are to be distinguished from the abnormal, unusual events which are excluded from AE's modeling of forecast outages. Each such event is examined on a case by case basis and the probability of the event occurring and the significance of the financial impacts are examined. If the event meets both criteria, in that the probability of the occurrence is low and the financial significance of the event is high, then these items are removed from AE's modeling, to ensure that the company is only compensated once for the occurrence, that being via the Reserve. Before charging business interruption costs to the Reserve, AE follows a process that enables it to confirm that the problem encountered is not due to inadequate maintenance practices, but is a legitimate candidate for the Reserve. This process involves retaining independent technical consultants to examinee the incident and its cause, working with AE's insurers to confirm their view that this is an insurable event, and obtaining legal advice with respect to any possible recourse from manufacturers or other third party suppliers.

AE noted the suggestion from Intervenors that there is a double recovery because work, which was supposed to be done during a planned outage, was done during an unscheduled forced outage. AE maintained that it was inappropriate to seek such an offset. AE stated that it is prudent for a utility to attempt to do at least a portion of the work associated with planned outages while a unit is down due to an unscheduled, forced outage. AE submitted that it was inappropriate to focus on a particular unit over a short period of time and suggest that, because the company adopted good operating and maintenance practices, it should be penalized. AE referred to the table entitled "Total Equivalent Outage Time – Planned Versus Actual Less UOV Charged to Reserve for Injuries and Damages" from Exhibit 144 and noted that, on an overall basis, the performance of the AE's generating units have a net negative position of 177,115 MWh over the years 1996 to 1998. AE suggested that such an approach is in contradiction to the forward test year method of regulation. AE also stated that, if planned maintenance extends for a period of time beyond which it was originally forecast AE has no recourse to seek to have its forecast adjusted to recognized the longer period of actual outage and seek compensation above that included in the forecast.

AE noted that, when a unit is out of service due to a forced outage, AE loses the ability to benefit from the surplus/shortfall that is incorporated in the Reservation Price for that unit. These losses are not included in the amount charged to the Reserve. If an amount attributed to the planned outages not taken is credited against the amount of UOV payments charged to the Reserve, then the surplus/shortfall not claimed against the Reserve should also be recognized. AE submitted that this offset almost entirely counters the variance attributable to planned versus actual outage days. However, AE recommended that no offset to the amounts claimed to the Reserve for UOV payments should take place.

AE also noted the submission that pool price could increase due to certain units being out due to a forced outage and that AE could receive a benefit from its other units. AE submitted that it did not receive offsetting benefits from its other units during a period of time when the H.R. Milner and Battle River 4 units were out of service due to a forced outage. AE noted that these units have a combined capacity of less than 4% of the total Alberta generating capacity and would not be expected to have a material impact on prevailing pool prices. AE stated that there were other factors that are more likely to have a greater impact on pool prices. To attribute the entire noted surplus to AE's generating units being out of service would be to ignore the more significant influences. AE stated that while it indicated a surplus of $921,044 during the time of the outages, little, if any, of the surplus was attributable to the Milner and Battle River 4 outages. AE suggested that the surplus amount is more likely a result of a combination of factors such as overall supply and demand, the impact of weather and other seasonal effects, the performance of other larger third party generating units and the level of imports/exports.[4] AE submitted that this also contradicted the suggestion by the FIRM Customers that AE derived a benefit of $1.1 million due to an increase in pool price resulting from outages at its units.

AE noted that it maintained a broad based insurance policy that covers a wide variety of events including "extra expense" that would cover business interruption insurance after the expiry of a deductible period of 60 days. AE highlighted the section of the insurance policy that excluded an accident being due to corrosion. The incident at H.R. Milner respecting the cracked rotor was due to stress corrosion cracking and therefore it would not be covered by AE's insurance policy. Insurance to provide such coverage would cost in the order of $3.0 to $3.5 million per year or about $80 million over the unit's life. Therefore, AE submitted that it was a prudent commercial decision to self-insure with the costs to ratepayers being less than if insurance had been obtained. AE submitted that the FIRM Customers misconstrued the AE evidence. AE clarified that while the cracked rotor incident was excluded from AE's insurance policy, it was an insurable event – the decision to insure was not taken given the magnitude of premiums. AE noted the FIRM Customers argument that the cracked rotor at H.R. Milner was not sudden and accidental. AE stated that the cracked rotor was found while the H.R. Milner unit was down to repair broken shrouding. Once the cracked rotor was found, it would have been imprudent to ignore the discovery and put the unit back together knowing that there could be a breakdown at any point in the future. However, by the reasoning of the FIRM Customers such a subsequent failure would have allowed a claim to the Reserve, as it would have been a sudden and catastrophic event. AE submitted that it was illogical to disallow this claim against the Reserve because AE followed a sensible approach.

AE stated its concern with the problems encountered at H.R. Milner and ensured that the events were not due to maintenance practices and that a valid claim against the manufacturer was not available. AE adopted the following process regarding H.R. Milner:

[4] Exhibit 144

- Retained independent consultants to review the events and assess the work of Hitachi, the manufacturer.
- Worked with the insurer to determine that the events were insurable and to see if any valid claims existed.
- Obtained independent legal advice regarding the likelihood of success of any claims made against the manufacturer.

AE submitted that it took reasonable steps and prudent measures to verify the legitimacy of a claim to the Reserve. With respect to some of the more minor claims against the Reserve, AE submitted that it has supported the inclusion of each of these items in the Reserve.

With respect to the FIRM Customers submissions on the possible causes of the failed turbine blades at both the H.R. Milner and Rainbow generating units, AE maintained that it followed a prudent course of conduct with respect to the examination of these failures. AE stated that it had examined the possibility of a third party claim but was not able to find a basis to support such an action. There is no definitive evidence to show that a manufacturer provided either inferior materials or anything other than good workmanship.

AE noted that it filed its Generation department policies and procedures (part of Exhibit 179). AE submitted that this filing illustrates that AE has in place formalized processes and procedures that ensure that relevant documents are accumulated and retained and that cost control measures are implemented. AE also noted its commitment to update the existing Policies and Procedures to reflect recent developments.

AE submitted that the FIRM Customers abused the process by introducing new evidence in argument. AE submitted that the related portions of the argument should be stricken from the record. AE added that, for the Board to base its decisions on information not in evidence would constitute a reviewable error of law.

AE noted that TransAlta, EPGI and AE have always had differences in the manner in which they have used their respective Reserves. Other differences also exist in the treatment of related items such as the manner in which the availability statistics for generating units are derived. For example, EPGI uses a five-year rolling average of actual performance for its availability statistics whereas AE removes abnormal outages from its 5-year average. AE noted that using an alternate approach would have allowed it to mitigate the need to rely on the Reserve to provide compensation for the risks of abnormal outages.

With respect to the FIRM Customers argument regarding an alternate methodology for claiming business interruption losses to the Reserve, AE questioned how the FIRM Customers proposal would work in practice. AE submitted that there was no evidence introduced to suggest that this approach would be beneficial or prudent for ratepayers and the FIRM Customers proposal would leave AE exposed to losses that it would incur during the period where a reduction in the deductible period has been assumed. AE stated that it already assumes the risk associated with

normal outages in its planning assumptions, as reflected by the fact that UOV payments were not claimed for the majority of outages incurred over the 1996 to 1998 period. AE questioned how the FIRM Customers proposal could be implemented on a retroactive basis particularly as there were no agreed upon modeling assumptions reflected in the 1997 and 1998 negotiated settlements. AE further stated that the FIRM Customers proposal appeared to establish a minimum timeframe below which no claims would be eligible for inclusion in Reserve. AE suggested that this could lead to additional claims to its Reserve given the significant number of outages experienced by AE for which UOV payments were not claimed to the Reserve.

AE questioned the recommendation of the FIRM Customers that any disallowed claims to the Reserve would require an associated adjustment for income taxes. AE stated that any such income tax adjustment was inappropriate in the context of a consideration of the Reserve. AE clarified that if $1,000 of claims incurred in 1997 or 1998 for generation outages were disallowed, the Reserve balance would be reduced by $1,000. This would result in a decrease in the provision for Injuries and Damages by $100 per year beginning in 1999 (based on a 10-year amortization period for the generation reserve balance). Since there is also a corresponding reduction of $100 in the ten year amortization of the Reserve balance as a result of the $1,000 disallowed claims, there would be no change in the utility income tax component included in the revenue requirement for 1999 and 2000.

In response to IPCAA, AE clarified that it does not collect from the 1997 and 1998 surplus/shortfall negotiated settlement deferral accounts any amounts that that are booked to the Reserve. AE noted that this is demonstrated in the footnotes to the surplus/shortfall negotiated settlements for 1997 and 1998. Therefore there is no double-dipping taking place as suggested by IPCAA.

AE noted ENMAX's argument regarding the amount of discretion that lies with AE regarding the definitions and criteria employed to determine whether or not an item properly qualifies for inclusion in the Reserve. AE acknowledged that the initial assessment of whether an event meets the established criteria occurs on a case-by-case basis and rests with it. However, AE submitted that there are built in safeguards such as an examination by an independent insurance adjuster. Also, the Phase I proceeding provides an open forum where all parties can challenge each item booked to the Reserve, to ensure their legitimacy before the costs associated with the items are included in AE's revenue requirement.

Board Findings

The Board agrees with the FIRM Customers that coverage principles under self-insurance should follow those under commercial insurance. The Board considers it appropriate that the Reserve should continue to be used to cover the deductible portion of insured losses, including any portion of the loss not covered by insurance policies. In addition, the Board considers certain uninsurable losses to be covered by the Reserve.

2. RESERVE FOR INJURIES AND DAMAGES

The Board considers that the Reserve should only compensate AE for injuries and damages that are outside the normal business risks for which AE is compensated through test year forecasts and the fair return. The Reserve should not be used for losses that are within the normal business risks for which AE is already compensated.

With respect to the alleged abuse of the process, the Board agrees with AE that if the Board were to base its decisions on information that is not in evidence this would constitute a reviewable error of law. However, the Board considers that parties are entitled to make their argument using any evidence that is on the record. The Board notes that, to preserve fairness, the Board's process allows parties the right to reply to any such arguments. Further, the Board placed the appropriate weight on all evidence that it has allowed on the record in arriving at its Decision.

The Board considers that it must address the following issues:

- What portion of the UOV payments should be borne by AE, the Reserve and/or the TSR?
- Should the UOV payments be offset by the benefit to AE, if any, of higher pool prices?
- The prudence of specific claims to the Reserve.

The Board has modified the suggestions of the FIRM Customers to categorize the cost recovery of each business interruption loss resulting from sudden and accidental outages as follows:

- The first portion of the recovery for business interruption would be through the planning assumptions for both insurable and uninsurable events. This portion would be chargeable to AE since AE is already compensated for these events through the planning process.
- The second portion of the recovery would be from the TSR for relief of UOV payments for those events having an outage of greater duration than covered by the planning assumptions.
- The third portion of the recovery for insurable events would be by way of commercial insurance.

With respect to the first portion of the recovery, the Board considers that there is a fundamental disconnect between AE's modeling of forecast outages for planning purposes and AE's charges for extraordinary outages to the Reserve. The Board, at Tr. p.5618, questioned why the service hours of the unit should not be increased by the extraordinary outages for the purposes of calculating normal FMOR outage statistics. AE responded, in Exhibit 207, that the extraordinary outages could be considered as notional running time provided that " the normal forced and maintenance outage rate must also be applied during that notional running period to preserve the normal characteristics for the unit." The Board considers that Exhibit 207 provides the insight that extraordinary outages should also have the FMOR rate applied in order to be consistent with the method used to calculate normal FMOR outage statistics. In other words, AE is already being compensated for an equivalent FMOR percentage during the time of the extraordinary outage. Accordingly, the Board considers that the expected availability percentage (i.e. 100%-FMOR%) times the extraordinary outage time and costs should be the portion charged to the reserve.

Therefore, the Board considers that UOV charges to the reserve for H.R. Milner, Battle River 4 and Rainbow 1 and 2 should be reduced by the UOV costs times the planned FMOR rate for each unit.

The Board notes, with approval, that any business interruption included in the Reserve has been excluded from the availability statistics used as an input to generation modeling.

With respect to the second portion of the recovery, the Board agrees with ENMAX that AE has not set out objective criteria to distinguish between events which are "normal" events which should be charged to the Reserve and those events which should face a more rigorous test under the TSR.

Further, with respect to the general issue of whether UOV payments should even be charged to the Reserve, the Board notes that the three Utilities have different approaches to this issue. The Board notes that there is no specified limit in the legislation that restricts the length of time after an event within which a Utility can apply to the Board for a TSR. Accordingly, in order to have consistent treatment of the three Utilities, the Board has determined that claims for recovery of UOV payments from any Utility should be on the same basis. The Board has determined that this should be through the TSR mechanism. The Board considers that this policy should be implemented on a going forward basis effective 1 January 1999.

The Board will now deal with the issue of whether the UOV payments charged to the Reserve in the past should be offset by the benefit to AE, if any, of higher pool prices. The Board considers that it is difficult to precisely quantify the effect that the outage has on pool prices and the corresponding appropriate amount of the offset. The Board notes that 50% of the net AE surplus/shortfall in 1997 and 1998 went to customers pursuant to the Board approved negotiated settlement for those years. Notwithstanding the above, the Board considers that it would be appropriate for AE to include a modest $1.25 per MWh, applied to the net AE surplus/shortfall MWh in each hour of the outage event, as a revenue offset or cost addition to the UOV costs during each outage event. The Board has arrived at this rate by taking 50% of the $2.50-$2.70 /MWh increase in pool price of a 1.5% (i.e. 115 MW) increase in provincial load for the year 2000.[5] The Board notes that the weighted average of the H.R. Milner, Battle River 4 and Rainbow 1 and 2 outages is in the order of 118 MW. The Board considers that AE should neither benefit nor lose as a result of the deemed change in pool price. Accordingly, the Board considers it appropriate that the deemed price increase of $1.25 per MWh, should be applied to the net AE surplus/shortfall MWh in each hour of each outage event during 1996,1997 and 1998. The Board notes that 100% on price and 90% on volume of the net AE surplus/shortfall goes to customers during the 1999 and 2000 test years pursuant to the Board approved negotiated settlement.

The Board agrees with ENMAX that the Reserve should be credited for saved days when forecast planned maintenance is done during forced outages. However, the Board also agrees

[5] IPPCA Evidence, Volume II, Section 1, p.12

with AE that the Reserve should be charged with the loss of surplus foregone when a unit is out of service due to a forced outage. The Board notes from Exhibit 186 that these factors are close to offsetting for the extraordinary outages that occurred in 1996, 1997 and 1998. Accordingly, the Board will not make any retroactive adjustment for these factors. The Board also considers it unnecessary to make an adjustment for these factors during 1999 and 2000.

The Board will now deal with the following individual claims to the reserve:

- H.R. Milner Cracked Rotor
- H.R. Milner Turbine Blades and Shrouding
- Rainbow Turbine Blades

The Board agrees with the FIRM Customers that the repair to the cracked rotor on the H.R. Milner unit during 1998 was not a sudden and accidental breakdown of the rotor and did not arise as a result of any of the factors listed in AE's criteria. In particular the Board notes that the rotor was 25 years old and considers that this supports the claim that the breakdown was due to wear and tear and not as a result of an accidental breakdown. Accordingly, the Board considers that the $1.62 million of capital costs should be treated as a capital maintenance item and be removed from the Reserve. The Board considers that the $5.06 million UOV charges should also be removed from the Reserve consistent with the capital maintenance finding. It follows that it would also be appropriate for AE to reinstate the outage of 75 days associated with the cracked rotor in its FMOR statistics. However, the Board notes that AE, by virtue of the Settlement for 1999 and 2000, is precluded from receiving the benefit that would arise from the revised higher FMOR statistics. For this reason, the Board considers that it would be appropriate to only remove 80% of the UOV charges to recognize the foregone benefit to AE. Accordingly, the Board considers that only $4.0 million of UOV charges should be removed from the reserve. The Board considers that the remaining $1.06 million of UOV charges left in the reserve will adequately compensate AE for the foregone FMOR benefits.

The Board notes that AE repaired damaged turbine blades and shrouding at H.R. Milner during the 6 October 1997 outage and that the same turbine blades and shrouding had to be repaired 2½ months later in the 3 March 1998 outage. The Board is not persuaded that AE acted in an imprudent manner. The Board expects AE to pursue any legal remedies that would provide for the recovery of all or a portion of the costs. The Board directs that any monies recouped by AE shall be submitted to the Board for approval prior to being paid into the Balancing Pool. The Board also notes that companies have a variety of options available to them, prior to undertaking legal action against suppliers for work deficiencies. However, this requires early attention and action when concerns about service and repairs are noticed. These actions include withholding payment until the matter or concern is resolved.

The Board notes a similar situation with the turbine blades on the Rainbow 2 unit. The 13 April 1998 outage was caused by improper restoration of the turbine blades by a contractor in 1997. The Board is not persuaded that AE has acted in an imprudent manner. Again the Board expects

AE to pursue its remedies and recover as much of the costs as possible and directs that any monies recouped by AE shall be submitted to the Board for approval prior to being paid into the Balancing Pool.

The Board notes that, during the hearing, AE stated that it would credit the Reserve for the five days of UOV payment which are covered by the insurance policy with respect to the 6 October 1997 outage at H.R. Milner. This reflected AE's reduction in its deductible from 90 days to 60 days that was changed in early 1997.

The Board directs AE, in its refiling, to make adjustments to the Reserve balance and consequential amortization as follows:

- Reduce the UOV charges to the reserve for 1996, 1997 and 1998 for H.R. Milner, Battle River 4 and Rainbow 1 and 2 by the UOV costs times the planned FMOR rate for each unit. (the planned FMOR shall be the average of the approved 1996 and 1999 FMOR rates for each unit)
- Include a credit or charge derived from a $1.25 per MWh deemed pool price increase applied to the net AE surplus/shortfall MWh in each hour of the outage event as a revenue offset or an additional cost to the UOV charges to the Reserve during each outage event in 1996, 1997 and 1998.
- Remove $1.62 million of capital costs and $4.0 million of UOV charges from the Reserve with respect to the H.R. Milner cracked rotor.
- Credit the Reserve for the five days of UOV payment which are covered by the insurance policy with respect to the 6 October 1997 outage at H.R. Milner.

The Board directs AE to incorporate the following into its policies and procedures respecting charges to the reserve effective 1 January 1999:

- The Reserve shall not be charged with UOV payments for any events subsequent to 1 January 1999. Applications for relief of UOV payments shall be made via the TSR mechanism. Applications for TSR should reflect appropriate adjustments, similar in methodology, to that used by the Board in this Decision and included in the above directions.
- Only insurable and uninsurable events that are significant and of low probability shall be charged to the Reserve.

The Board directs AE to modify and update the business practices processes and procedures for charges to the Reserve as set out on Exhibit 179 effective 1 January 2000.

AE noted that a final closure of its Reserve will be required post-2000 to account for any charges to the Reserve after the cutoff date for the filing of AE's Application in 1998 until the end of 2000.

2. RESERVE FOR INJURIES AND DAMAGES

The Board denies AE's request to seek full recovery of the unamortized portion of the Reserve by the end of 2000 in the event that the IAT does not provide for recovery of the remaining amount through the PPAs.

The Board directs AE to apply to the Board for final disposal of the closing balance of the Reserve as at 31 December 2000. At the time of the application, the Board will review the charges to the Reserve, a report on attempts to recover amounts on the H.R. Milner and Rainbow 2 turbines matters, and the disposition of any remaining balances in the Reserve. Depending on the level of the balance in the Reserve, the Board will consider the appropriateness of amortizing any amounts still be to be collected or any positive balance through the Balancing Pool as well as the length of time over which the balance would be amortized.

3. QUALITY OF SERVICE

Board Findings

In Part 4–TAU, Section 4(d) of this Decision, the Board deals with the issue of quality of service measures for TransAlta's DISCO. A direction was given to TransAlta to provide measures that address the quality of service provided by TransAlta.

The Board initiated a process to deal with quality of service issues for all regulated utilities on a generic basis. However, the matter was not pursued with respect to electric utilities due to the restructuring activities that were underway. As this issue presented itself in this proceeding, the Board provided directions to TransAlta and, absent the negotiated settlement which AE entered into, the Board would have made similar directions to AE. The Board also considers that, in its future surveillance activities, the Board will pursue the matter of quality of service measures with AE.

4. REGULATED AND UNREGULATED ACTIVITIES

Board Findings

In Part 1–General, Section 2(c)(3) of this Decision the Board directed TransAlta to provide information in future GTAs on affiliate transactions. Due to the negotiated settlement which AE entered into, parties did not address this matter in these proceedings with respect to AE. However, the Board considers it appropriate that all of the Utilities should address the area of affiliate transactions in future GTAs. Therefore, the Board directs AE to keep track of and report on, in future GTAs, the amount of manpower used by non-regulated entities from the regulated AE affiliates. The report should include the number of hours, the rate at which labour is charged out and how the charge rate was determined. A breakdown should be included for work done for non-regulated affiliates in Alberta and those that are outside of Alberta. The Board considers that this will aid in providing an appropriate level of transparency in the relationships between AE and its non-regulated affiliates.

The Board wishes to further understand the relationships between amounts that are charged to or received from the unregulated affiliates of the regulated affiliates. Accordingly, in future GTAs, the Board directs AE to provide the following information on contracts or services that result in amounts being charged to the regulated utility by unregulated affiliates or that the regulated utility charges to unregulated affiliates:

- A list of services provided or received.
- The annual amount associated with those services.
- The contract or service agreement supporting those charges.
- How the rate or charge was determined and how does it relate to a market assessment of the reasonability of those charges.

Part 2 – AE

5. SUMMARY OF BOARD DIRECTIONS

This section is a summary[6] of Board directions to AE in this part. The Directions in *italics* are to be complied with in the 1999 refilings. The remaining directions are to be complied with in the future or at the time of the next GTA.

1. The Board directs that any monies recouped by AE shall be submitted to the Board for approval prior to being paid into the Balancing Pool. [Section 2]

2. Again the Board expects AE to pursue its remedies and recover as much of the costs as possible and directs that any monies recouped by AE shall be submitted to the Board for approval prior to being paid into the Balancing Pool. [Section 2]

3. *The Board directs AE, in its refiling, to make adjustments to the Reserve balance and consequential amortization as follows:*
   - *Reduce the UOV charges to the reserve for 1996, 1997 and 1998 for H.R. Milner, Battle River 4 and Rainbow 1 and 2 by the UOV costs times the planned FMOR rate for each unit. (the planned FMOR shall be the average of the approved 1996 and 1999 FMOR rates for each unit)*
   - *Include a credit or charge derived from a $1.25 per MWh deemed pool price increase applied to the net AE surplus/shortfall MWh in each hour of the outage event as a revenue offset or an additional cost to the UOV charges to the Reserve during each outage event in 1996, 1997 and 1998.*
   - *Remove $1.62 million of capital costs and $4.0 million of UOV charges from the Reserve with respect to the H.R. Milner cracked rotor.*
   - *Credit the Reserve for the five days of UOV payment which are covered by the insurance policy with respect to the 6 October 1997 outage at H.R. Milner.*

   [Section 2]

4. The Board directs AE to incorporate the following into its policies and procedures respecting charges to the reserve effective 1 January 1999:
   - The Reserve shall not be charged with UOV payments for any events subsequent to 1 January 1999. Applications for relief of UOV payments shall be made via the TSR mechanism. Applications for TSR should reflect appropriate adjustments, similar in methodology, to that used by the Board in this Decision and included in the above directions.
   - Only insurable and uninsurable events that are significant and of low probability shall be charged to the Reserve. [Section 2]

[6] This summary has been prepared for the convenience of all parties. The directions in the main body of the Decision shall prevail over this summary if there are any differences.

5. The Board directs AE to modify and update the business practices processes and procedures for charges to the Reserve as set out on Exhibit 179 effective 1 January 2000. [Section 2]

6. The Board directs AE to apply to the Board for final disposal of the closing balance of the Reserve as at 31 December 2000. At the time of the application, the Board will review the charges to the Reserve, a report on attempts to recover amounts on the H.R. Milner and Rainbow 2 turbine matters, and the disposition of any remaining balances in the Reserve. [Section 2]

7. Therefore, the Board directs AE to keep track of and report on, in future GTAs, the amount of manpower used by non-regulated entities from the regulated AE affiliates. [Section 4]

8. Accordingly, in future GTA's, the Board directs AE to provide the following information on contracts or services that result in amounts being charged to the regulated utility by unregulated affiliates or that the regulated utility charges to unregulated affiliates:
   - A list of services provided or received.
   - The annual amount associated with those services.
   - The contract or service agreement supporting those changes.
   - How the rate or charge was determined and how does it relate to a market assessment of the reasonability of those charges. [Section 4]

6. ORDER

THEREFORE, IT IS ORDERED THAT:

(1) ATCO Electric Ltd. shall file its Reserve for Injuries and Damages, its Transmission Terms and Conditions and its 1999/2000 Transmission Capital Additions on or before 16 December 1999, incorporating the findings of the Board in this Decision.

Dated in Calgary, Alberta, on 25 November 1999.

ALBERTA ENERGY AND UTILITIES BOARD

N. W. MacDonald, P.Eng.
Presiding Member

B. T. McManus, Q.C.
Member

A. J. Berg, P.Eng.
Member

Part 3 – EPGI/EPTI

TABLE OF CONTENTS

1. GENERAL 415

(a) Accounting Practices 415

(b) Allocation of Common Costs 416

(c) Incentive Compensation 420

(d) Self-Insurance Reserve 429

(e) Hearing Cost Reserve 430

(f) Y2K 432

(g) Return on Decommissioning Reserve 433

(h) Inflation Assumptions 442

2. EPGI 444

(a) Rate Base 444

(1) Capital Additions 444

(A) Historical vs. Forecast Capital Expenditures Levels 444

(B) Mine Related Capital Expenditures 448

(C) Clover Bar Capital Expenditures 451

(D) Genesee Black Start and Clover Bar Black Stop Projects 455

(E) Rossdale Decommissioning Costs 459

(F) Projects of less than $1.0 million 461

(G) 1992 Clover Bar IP Rotor Replacement and 1993 Insurance Claim 462

(H) Summary of Capital Additions 468

(2) Necessary Working Capital 469

(A) Operating Expenses 469

(B) Dividend Payment 472

(C) Inventory Valuation at 31 December 2000 473

(D) Board Findings 473

(b) Minimum Return Margin 474

(c) Cash Operating Expense 481

(1) Dragline Operating Benefits 481

(A) The Board's Jurisdiction 482

(B) Relevance of the Boyd Report 492

(C) Value of the Operating Benefit 500

(2) Fixed Fuel Cost 504

(3) Variable Fuel Cost 507

(A) Coal Costs 507

(i) The Agreement between EPGI and Fording Coal Limited 508

(ii) Variable Coal Costs 515
(B) Variable Natural Gas Costs 519
(4) Operating and Maintenance 519
(A) Fixed and Variable Production 521
(B) Maintenance and Repair 525
(C) Generation Administration 535
(D) Corporate Services 538
(E) Summary 539
(5) Taxes Other Than Income Tax 540

(d) Depreciation 541

(1) Rossdale Decommissioning Costs 541
(A) Effect of the GUR on the Board's Ability to Modify Depreciation 541
(B) Effect of the GUR on the Mid-Year Depreciation Convention 548
(C) Prudence of Applied For Cost Increases 550
(D) Rossdale Decommissioning Allowed for 1999 and 2000 562
(2) Technical Update 568
(A) The Redistribution of Depreciation Reserves 572
(B) The 5% Threshold for Amortizing Reserve Imbalances 575
(C) The Segregation of the Decommissioning Reserve 578
(D) The Use of the Technical Update for Depreciation Rates 580
(E) Summary of Board Findings 583

(e) Reservation Price–Normalization Costs 583

3. EPTI 588

(a) Necessary Working Capital 588

(b) Cash Operating Expense 590

(1) Operating and Maintenance 590
(2) Taxes Other Than Income Tax 593

(c) Depreciation 595

4. SUMMARY OF BOARD DIRECTIONS 599

5. ORDER 604

Part 3 – EPGI/EPTI

1. GENERAL

(a) Accounting Practices

The accounting policies employed by EPGI in preparing the 1999 and 2000 cost forecasts were essentially unchanged from those employed by EPI in the 1996 GTA. However, EPGI identified differences from past policies.

Intervenors did not take issue with the accounting policies except for those topics specifically addressed by EPGI/EPTI.

Position of EPGI/EPTI

EPGI/EPTI addressed the following topics as changes from previous years' accounting practices.

(i) EPGI/EPTI prepared a Technical Update of the depreciation expense.

(ii) EPGI/EPTI, as part of the Technical Update, segregated the decommissioning reserve from the accumulated depreciation reserve as EPGI/EPTI considered this separation would allow for a more transparent tracking of the amount of the reserve.

(iii) EPGI/EPTI updated its working capital calculations for 1999 and 2000, by updating the various lead/lag schedules for current payment and receipt patterns. EPGI/EPTI stated many of the changes were minor in nature.

(iv) EPGI/EPTI proposed to capitalize all capital and operating expenses directly attributable to EPGI's Y2K Project. EPGI/EPTI indicated that costs incurred in 1998 and 1999 were held in CWIP accounts and would be added to rate base in 2000.

Position of the Intervenors

Intervenors did not take issue with the accounting practices of EPGI/EPTI other than for those topics noted above.

Board Findings

The Board has prepared, under separate sections of this Decision, its findings with respect to (i) the depreciation expense located in Part 3–EPGI/EPTI, Section 2(d)(2)(D) for EPGI and Part 3–EPGI/EPTI, Section 3(c) for EPTI; (ii) the segregation of accumulated depreciation between the depreciation reserve and the decommissioning reserve for EPGI located in Part 3–EPGI/EPTI, Section 2(d)(2)(C) and Part 3–EPGI/EPTI, Section 3(c) for EPTI; (iii) the working capital calculations located in Part 3–EPGI/EPTI, Section 2(a)(2) for EPGI and Part 3–EPGI/EPTI, Section 3(a) for EPTI; and (iv) the capitalization of Y2K expenses for EPGI and EPTI located in Part 3–EPGI/EPTI, Section 1(f).

1. GENERAL
(a) Accounting Practices

The Board notes that Intervenors did not comment on or object to EPGI/EPTI's remaining accounting practices.

The Board accepts the accounting practices for EPGI/EPTI for 1999 and 2000 as reasonable with the exceptions noted above and found elsewhere in this Decision.

(b) Allocation of Common Costs

Common costs consist of costs incurred by having one function do a common job for all other functions of the corporation. Such common activities include accounting, marketing, corporate services and information services (IS). The allocation of common costs to each function is generally accomplished by using allocators that represent the level of work performed for the function.

The objective for determining allocators is to ensure a fair and reasonable allocation over time and to reflect the principle of cost causation and the level of benefit each function receives as a result of incurring the common cost. Common costs can be categorized as directly assignable, allocable or, in some cases, unassignable all with the purpose to allow the function responsible for incurring the cost to recover that cost through the revenue requirement.

In Decision U97065, Board Direction G-7, the Board directed EPI "...to undertake detailed studies of their functional and cost allocation methodologies and incorporate the results of such studies in their next GRA." The Board also directed EPI, in Board Direction G-12, "...to carry out a detailed analysis of their computer system costs and recommend a more appropriate cost allocation methodology at the next GRA." EPCOR, in Appendix D of the EPGI evidence, set out the process for allocating corporate services costs and general plant assets to business units.

Intervenors were concerned with the allocation of IS costs to EPCOR's regulated and non-regulated business units.

Position of the Intervenors

The FIRM Customers prepared a table summarizing the functionalization of IS costs as a percentage of total IS costs for each of the three Utilities. The FIRM Customers concluded that EPGI/EPTI's allocation methodology resulted in a lower allocation of IS costs to the non-regulated distribution function than the other two Utilities. The FIRM Customers indicated that, overall, 51% of IS costs was allocated to EPDI whereas, AE and TransAlta allocated 90% and 58%, respectively, to the distribution function. The FIRM Customers submitted that EPGI/EPTI had an incentive to allocate as much of its IS costs to generation and transmission as possible as these costs would be shared by other DISCO's customers through the Reservation Prices and TA Tariffs.

The FIRM Customers expressed specific concern with EPGI/EPTI's allocation of IS costs to functions. The FIRM Customers noted that the allocation factors for the following three accounts

- I/S Capital - Corporate (account 23122),
- General Plant Data Processing Equipment (account 23180) and
- CBIS (account 23832)

were calculated, as set out in response to Information Request MI.EPGI-16(b), as, for EPGI, 45% for IS capital and 44% for IS operating costs and, for EPTI, 4% for both capital and operating costs.[7] The FIRM Customers noted that EPGI indicated there was a reduction of $0.1 million. However, the FIRM Customers concluded that the reduction for EPGI should have been $0.4 million, not $0.1 million. The FIRM Customers explained that the difference arose when the 45% allocation factor was applied to the total asset values in CCA.EPGI-26 and ENMAX.EPGI-14 (and the depreciation rates shown in Schedule G-19) and when the 10.6% cost of capital was applied to this difference.

The FIRM Customer's second concern related to the determination of the allocation factors shown in MI.EPGI-16(b). The FIRM Customers stated that EPGI initially discussed the determination of those allocation factors in Appendix D, page D-8, where "senior managers in the IS department then applied their best judgement, in an objective and impartial manner, to each project and determined appropriate allocations based upon the established criteria." EPGI confirmed the projects listed in MI.EPGI-16(b) were the projects referred to in Appendix D and covered only 70% of the IS expenditures.[8]

The FIRM Customers submitted that EPGI indicated the list of projects did not include the billing function.[9] While both AE (section 1.13) and TransAlta (section 5.3, Corporate Services) allocated billing or customer information systems costs 100% to distribution, EPGI appeared to exclude these costs from its "representative sample." The FIRM Customers suggested this inclusion explained why 90% of AE's IS costs were allocated to distribution.

In the absence of information on EPGI/EPTI's billing system and overall corporate information system costs, the FIRM Customers recommended that the 1996 GTA approved allocation of 37% and 5% to generation and transmission should be maintained as these allocations were more in line with those of the other utilities. The FIRM Customers estimated an additional $875,000 decrease to Accounts 23122, 23180 and 23832, resulting in a total reduction of $1.3 million to information systems.

The FIRM Customers noted that, although EPGI/EPTI provided a review of its new allocation methods, EPGI had not addressed the above issues. The FIRM Customers noted that the refinements invoked by EPI resulted in errors and omissions and since sufficient information to calculate the reduction in IS operating costs was not available, EPGI should be required to reflect the reduction of $1.3 million in its refiling.

---

[7] Tr. p.1435
[8] Tr. p.1431
[9] Tr. p.1432

Position of EPGI

EPGI stated the allocation of IS costs was part of the ongoing review and refinement of EPCOR corporate services costs. EPGI submitted the allocation was consistent with Board Decision U97065, Direction G-12, which directed the Utilities to conduct detailed analyses of their computer systems costs and recommend a more appropriate cost allocation methodology.

EPGI indicated that the methodologies employed by EPCOR for allocating corporate services IS costs to EPCOR's business units (regulated and non-regulated) had changed from that used in the 1996 GTA Refiling. EPGI explained that all application or infrastructure costs directly attributable to specific business units were directly allocated to those business units. The remaining costs were allocated on one of two bases. A reasonable amount of the costs was allocated to capital on the basis that corporate IS systems were used to manage capital projects. The remaining costs were allocated among business units based on weighted average allocation factors which represented senior IS management's best professional judgement of cost causation and use by function of the primary shared IS applications within EPCOR general plant.

EPGI asserted the FIRM Customers' arguments were based on a misunderstanding of the evidence. Firstly, EPGI noted, in MI-EPGI-16(b), that the first step in developing the allocators was to review all IS costs and, where possible, to directly assign to each individual business unit all applications and infrastructure costs which were determined to be directly attributable to that specific business unit. EPGI stated any capital projects related solely to EPDI, including billing system related items, were not included in the IS allocation process. In the same manner, EPGI stated that no projects directly associated with EPGI were included in the representative sample as all costs associated with those projects had been directly assigned to EPGI. With the exception of one minor Aqualta project, only corporate projects that were shared among all subsidiaries were used in developing the corporate IS allocation factors.

Secondly, EPGI suggested the FIRM Customers' analysis mischaracterized AE's allocation rates. EPGI submitted that Schedule 1.13 of AE's Application, used by the FIRM Customers in deriving the rates in their summary table, showed both the direct functionalization of computer systems to business units as well as the functional allocation of those systems shared by business units. EPGI suggested the resulting combined allocation rate was not comparable to EPGI's or EPTI's allocation rates as EPGI/EPTI's rates only related to the allocation of the shared corporate IS costs across the EPCOR group of companies. EPGI's allocation rate did not include IS costs directly assigned or functionalized to business units as did AE's allocation rate. EPGI concluded that the FIRM Customers' comparison was invalid and should be rejected.

Thirdly, EPTI submitted that the FIRM Customers' analysis failed to consider the differences in the scope or size of the operations comprising the generation, transmission and distribution functions of the three utilities. For example, EPTI noted that both AE's and TransAlta's transmission operations were larger relative to their other operations than were EPTI's operations relative to other business units in the EPCOR group. EPTI submitted size difference was one of many factors that would account for differences in allocation rates between the utilities.

EPGI acknowledged the allocation error to EPGI's accounts 23122, 23180, and 23832. EPGI indicated that the refiling would be consistent and include the allocation rates approved by the Board for EPGI's IS costs.

EPGI stated that the FIRM Customers had not challenged the underlying criteria of the allocation methodology. EPGI submitted that the FIRM Customers' comparative analysis was superficial and flawed, and did not provide any basis for the FIRM Customer's position. By contrast, EPGI submitted the evidence demonstrated that the criteria used in developing the IS allocation rates for EPGI and EPTI had produced rates which reflected use by function and cost causation. EPGI's use of a sample, comprised of 70% of the allocated projects that made up corporate IS capital and excluded projects that were directly assigned to a business unit, provided more than sufficient coverage of corporate IS operations and reliably represented corporate IS activities. EPGI submitted its proposed allocation of IS costs was based on logical criteria, was fair and reasonable, and should be approved by the Board.

Board Findings

The Board notes that the FIRM Customers have raised issues in respect to allocating common costs to the business functions. The Board notes that a comparison between the three utilities, for the overall allocation of common costs to each business unit, is a useful evaluation tool. However, the Board considers that such a comparison should have a consistent base in order to compare like activities between utilities. The Board notes EPGI/EPTI's variance explanation where directly assignable costs were excluded and only the remaining costs were included to calculate an allocation ratio which differs from the basis upon which AE derived a ratio of 90% of the IS costs allocated to the distribution function.

The Board notes the FIRM Customers' conclusion that the IS allocation factors, determined by EPGI/EPTI in response to MI.EPGI-16(b), were not used for allocating IS operating costs. The Board also notes EPGI/EPTI's acknowledgement that the allocation error would be corrected in the refiling. The Board accepts the explanation and the Board directs EPGI/EPTI to apply the determined ratios in the refiling.

The Board considers that the study prepared by EPGI/EPTI follows the intent of the Board's directions in Decision U97065. The Board notes that EPGI/EPTI has reviewed the allocation methodologies and as a result has used the direct assignment of costs to the appropriate business unit as a preferred allocator to achieve a cost causative allocation of costs to the business units.

The Board, seeing no evidence to the contrary, accepts EPGI/EPTI's methodology for allocating corporate service costs to the appropriate business units. The Board also accepts EPGI/EPTI's methodology for allocating IS costs to the functionalized business units. The Board, therefore, rejects the FIRM Customers' recommendation to continue using the 1996 GTA approved allocation and decrease the cost allocation by $1.3 million. Accordingly, the Board directs EPGI/EPTI, in their refilings, to apply the methodologies for allocating common costs, as presented in the Application.

(c) Incentive Compensation

For salaries and wages, EPGI stated that an adjustment factor of 3.2% was used in each of 1999 and 2000. EPGI explained that this adjustment factor was in keeping with the expected trend in salary and wage increases.

EPGI summarized salaries, wages and benefits included in the compensation program as follows:

EPGI ($ million)	1996 Refiling	1996 Actual	1997 Actual	1998 Refiling	1999 Forecast	2000 Forecast
Labour	8.505	7.731	8.023	8.414	9.715	9.647
Labour O/T	1.145	0.997	1.339	1.535	1.473	1.511
Salary	6.146	5.345	5.987	6.269	7.612	7.753
Salary O/T	0.066	0.094	0.113	0.127	0.157	0.141
Salary Charge-outs	0.005	(0.214)	(0.499)	(0.305)	(0.203)	(0.534)
Fringe Benefits	4.070	3.890	3.328	3.445	3.929	3.897
At-Risk Compensation		0.500	0.400	0.325	0. 650	0.650
Incentive Compensation		0.500	0.400	0.325		
Total	19.937	18.843	19.091	20.135	23.333	23.065

Source: ENMAX-EPGI.15(j)

EPTI summarized salaries/wages and benefits included in the compensation program as follows:

EPTI ($ million)	1996 Refiling	1996 Actual	1997 Actual	1998 Refiling	1999 Forecast	2000 Forecast
Base Wages/Salary	2.27	2.31	2.28	2.71	2.96	3.00
Inflation	0.05	0.05	0.05	0.07	0.06	0.06
Fringe Benefits	0.80	0.78	0.79	0.92	0.96	0.98
At-Risk Compensation		0.14	0.11	0.10	0.23	0.25
Incentive Compensation		0.14	0.11	0.10		
Total	3.12	3.42	3.34	3.90	4.21	4.29

Source: ENMAX-EPTI.08(j)

EPGI/EPTI indicated the structure for compensating its employees had three components:

- "base" compensation (including benefits),
- "at-risk" compensation and,
- "incentive" compensation.

1. GENERAL
(c) Incentive Compensation

The base compensation and at-risk compensation (collectively referred to as an employee's "target total compensation") was designed to bring employee total compensation to a level which was at par with comparable positions in the electrical utility industry and other similar sized companies in Alberta and Western Canada. The "base compensation" component was equivalent to approximately 85% to 97.5% of an employee's target total compensation, depending on the employee's position and level within EPGI/EPTI.

At-risk compensation was paid to employees when EPGI/EPTI met its annual targets. Employee target total compensation was factored into EPGI/EPTI's budget and was included in EPGI/EPTI's cost forecast. At-risk compensation was not included in EPGI/EPTI's cost forecast in the 1996 GTA as EPGI/EPTI's compensation structure was in transition. However, the actual costs reported for EPGI/EPTI GENCO/TRANSCO in 1996 include the at-risk component.

The incentive component of employee compensation was designed to compensate for employee performance that met or exceeded "stretch" objectives beyond annual targets. As a result, incentive compensation was funded from savings achieved through outstanding performance and, accordingly, was not included in EPGI/EPTI's cost forecast.

Reaching corporate annual performance targets, and thus being eligible for target total compensation or above target total compensation through incentive compensation, required the successful achievement of a variety of performance targets including financial performance, customer satisfaction, environmental performance, safety performance and productivity. For non-union employees, once the pool of available compensation had been set, payments were based on individual performance. For unionized employees, achievement of the target resulted in the same additional compensation for all employees. At-risk compensation was not linked to individual performance for unionized employees, therefore the performance targets had been set 5% higher than for non-unionized employees.

In summary, EPGI/EPTI summarized its employee compensation plan resulted in the following:

- below market total compensation for performance that failed to meet annual targets (base compensation component only),
- total compensation that was at par with market for performance that met annual targets (base compensation plus at-risk compensation) and,
- compensation that was above market for outstanding performance (base compensation plus at-risk compensation plus incentive compensation).

EPGI/EPTI noted that no party proffered evidence taking issue with either EPGI/EPTI's forecast of employee compensation or the manner in which that compensation was determined.

Position of the FIRM Customers

The FIRM Customers noted that EPGI/EPTI had an incentive compensation system allowing employees to obtain additional compensation based upon achieving or exceeding specified performance objectives.

The FIRM Customers noted EPGI/EPTI's compensation system distinguished between "at-risk" compensation and "incentive compensation." The FIRM Customers interpreted at-risk compensation to be payable when an employee met expected "normal" job requirements.[10] The FIRM Customers interpreted incentive compensation to be payable if an employee exceeded normal job requirements by meeting "stretch objectives."[11] As part of this process, the FIRM Customers understood that EPGI/EPTI attempted to have personal performance targets aligned with overall corporate targets.[12]

The FIRM Customers noted the EPGI/EPTI system established a single pool of money from which both at-risk and incentive compensation were payable.[13] The overall compensation pool was allocated to each of the business units with equal weight being given to the performance of the business unit and the overall corporate performance.[14]

The FIRM Customers noted EPGI/EPTI established performance targets for four areas: net income (40% weight), environmental performance (15% weight), safety (15% weight), and capacity/availability (30% weight).[15] The performance target for net income was based upon the corporate budget as approved in the regulatory process.[16] The FIRM Customers understood that money was made available for incentive compensation in the event actual overall corporate income exceeded budgeted income.

The FIRM Customers noted the capacity/availability performance target also had an impact on net profit. To the extent the capacity/availability performance target was exceeded, EPGI/EPTI would receive additional revenue thereby increasing net income. The weighting factors used by EPGI/EPTI resulted in performance targets with 70% of the weight being given to income or income related items.

The FIRM Customers stated EPGI/EPTI indicated typically 90% of all employees received at-risk compensation, whereas 70% would receive incentive compensation.[17] The FIRM Customers stated the number of employees receiving at-risk compensation was understandable, as one

[10] Tr. p.1069
[11] CCA.EPGI-06(c)(d); ENMAX.EPTI-08(d)(e)
[12] Tr. p.1077
[13] Tr. p.1066
[14] Tr. p.1079
[15] CCA.EPGI-06(c); ENMAX.EPTI-08(d); Tr. p.1078; Tr. p.1081
[16] Tr. p.1079
[17] EAL.EPTI-70; Tr. p.1070

would expect 90% of employees to achieve "normal" performance standards. However, the FIRM Customers suggested the number of employees receiving incentive compensation indicated a very substantial number of employees exceeded "normal" performance standards. The FIRM Customers queried whether EPGI/EPTI employees were truly performing that well or was this an inevitable outcome of this type of compensation system. The FIRM Customers submitted the latter was more likely.

The FIRM Customers noted the incentive compensation for EPGI/EPTI employees was overwhelmingly tied to corporate profits. Each employee had a personal stake in the profit of the company and the compensation system was designed to achieve this result. However, the FIRM Customers stated the yardstick for corporate profits were measured against a budget. Therefore, the FIRM Customers submitted each employee had a personal stake in seeing budgeted profit targets were exceeded. This action included the people preparing the forecasts ultimately used in the preparation of the budget for both internal and regulatory purposes.

The FIRM Customers acknowledged providing incentives to employees might increase the productivity and performance of employees. However, in a regulatory context, this incentive was somewhat akin to putting the fox in charge of the hen house. The FIRM Customers suggested it was in the best personal interests of each employee to see budgeted profit targets were exceeded. Consciously or unconsciously, human nature can have a way of affecting the preparation of forecasts, and ultimately, budgets. The FIRM Customers submitted that, at the very least, there was a built-in "incentive" to err on the conservative side when preparing forecasts which, in turn, would affect budget line items.

The FIRM Customers submitted that compensation systems of this type taint the perceived objectivity of the forecasting process. When personal income was at stake, it became all too easy to generously estimate costs and conservatively estimate revenues. The FIRM Customers submitted EPGI/EPTI's incentive compensation system caused an imbalance in the forecasting process. When the income of individual employees was impacted by the forecast for costs and revenues, it was inevitable a cloud of suspicion would be cast over the forecasts. The FIRM Customers believed such suspicions were warranted and submitted these were concerns the Board should take into consideration when reviewing EPGI/EPTI's forecasts.

Based on the foregoing, the FIRM Customers urged the Board give careful consideration to the possible and very probable impact these incentive schemes might have on EPGI/EPTI's forecasts, particularly where historical data suggested a pattern of over-forecasting.

The FIRM Customers noted EPGI's explanation for the labour increase in 1999 over 1998 as a result of $0.5 million escalation and $0.8 million for additional staff and reclassifications. The FIRM Customers also noted EPGI's reason for a decrease in 2000 over 1999 was a $0.5 million escalation offset by a $0.6 million reduction in staff.

The FIRM Customers noted the $0.5 million escalation, was higher than the 3.2% escalation rate EPGI stated it used in the Application. The FIRM Customers further noted, to be consistent with the collective agreement escalations experienced in 1997 and 1998, the labour escalation in 1999 should be reduced by $0.2 million to $0.3 million for 1999 and 2000, respectively.

When the FIRM Customers questioned EPGI with respect to the continuing high level of labour overtime in spite of the filling of vacancies in 1999, the following response was given:

> Q. Can you tell me what the reason is for the overtime increase from 1996 to 1999. That is as compared to the 1996 and 1997 actuals.
>
> A. MR. TOPPING: It tends to follow the labour component, so the more work we do, the more labour dollars there will be, and that is a reflection of the amount of turnaround work, and it ends up getting reflected equally in the labour overtime.[18]

The FIRM Customers submitted that, despite this verbal testimony, the evidence suggested the level of turnaround activity in 1999 was comparable to that in 1998. In 1998, the turnaround activity consisted of one major at Genesee, two minors at Rossdale and one major and one minor at Clover Bar. In 1999, the turnaround activity included one major at Genesee one minor at Rossdale and one major and two minors at Clover Bar.[19] In addition, the FIRM Customers suggested the proposed increase in staffing should also result in offsetting or greater reductions in labour overtime. Therefore, the FIRM Customers recommended that the 1999 labour overtime expense should be reduced by $0.8 million.

The FIRM Customers noted, for 2000, that EPGI proposed a decrease in labour costs commensurate with the reduction in level of turnaround activity. However, consistent with the reasoning for 1999, the FIRM Customers recommended that the 2000 labour overtime expense should also be reduced by $0.8 million.

The FIRM Customers noted the proposed salary increase in 1999 over 1998 consisted of $0.2 million escalation, $0.7 million for additional staff for the technical services and risk management functions, $0.2 million for filling of vacancies and $0.2 million severance costs. The FIRM Customers also noted the 2000 increase was entirely due to escalation of $0.2 million.

The FIRM Customers' concern related to the inclusion of $0.2 million provision for severance costs. In the absence of any benefits related to severance in either of the two test years, the FIRM Customers recommended the $0.2 million severance provision included in 1999 and 2000 salaries be disallowed.

---

[18] Tr. p.1027
[19] EAL-EPGI.14

In summary the FIRM Customers recommended the following reductions to EPGI's salaries and labour:

	1999 $ million	2000 $ million
Reduction in labour escalation	0.2	0.2
Reduction in labour overtime	0.8	0.8
Reduction in salaries severance provision	0.2	0.2
Total	**1.2**	**1.2**

Position of EPGI

EPGI suggested the FIRM Customers attempted to cast suspicion on the reasonableness of the 1999 and 2000 cost forecast by asserting that it was "possible and very probable" that the employee compensation program had created bias in EPGI's cost forecast. However, EPGI suggested the FIRM Customers failed to point to any substantive evidence showing that EPGI's compensation program had created any bias in EPGI's cost forecasts.

EPGI emphasized there was no reliable basis for the FIRM Customers' assertions. EPGI submitted, while there was always a "possibility" of bias being introduced in a forecasting process, there was no evidence which demonstrated that such bias existed, or that it was even likely bias existed in respect of EPGI's forecasts. EPGI submitted, to the contrary, that a detailed explanation was provided outlining the steps taken during the 1999/2000 budget process and referred to the testimony of Mr. Vaasjo where he testified that EPGI had checks and balances in place to ensure that costs were maintained at prudent and reasonable levels.[20]

The FIRM Customers claimed that the following reductions should be made to EPGI's forecast labour and salaries costs. EPGI indicated inconsistencies in the FIRM Customers' recommended reductions. Firstly, the FIRM Customers argued that EPGI's labour escalation should be reduced by $0.2 million in each of 1999 and 2000 which would be consistent with the collective agreement escalations experienced in 1997 and 1998.

EPGI responded to an undertaking, Exhibit 37, which provided an explanation of how the 3% labour escalation was used to derive the applied-for $0.5 million increase, and demonstrated the reasonableness of the forecast escalation factor. EPGI submitted that the evidence was more reliable in determining the reasonableness of the 3% escalator than comparisons with 1997 and 1998 escalators proffered by the FIRM Customers.

And secondly, EPGI noted the FIRM Customers argued that EPGI should reduce forecast labour overtime expense for 1999 by $0.8 million. EPGI stated the FIRM Customers argued that, notwithstanding the evidence of EPGI at Tr. p.1027, "the evidence suggests the level of

[20] Tr. p.301

turnaround activity in 1999 is comparable to that in 1998" and, in addition, stated that "the proposed increase in staffing should also result in offsetting or greater reductions in labour overtime." EPGI noted the FIRM Customers argued for a similar reduction in forecast labour overtime expense in 2000 based on the same reasoning.

In the referenced passage, EPGI was responding to a question relating to the increase in overtime in 1999 relative to 1996 and 1997 actuals. EPGI submitted the question and response had nothing to do with reasons for increases from 1998 to 1999. Accordingly, EPGI submitted the FIRM Customers took the testimony out of context. EPGI stated the testimony indicated that the level of turnaround activity in 1998 and 1999 was far greater than in 1996 and 1997 and the increase in overtime from 1996/1997 levels to 1999 forecast levels was consistent with the increased turnaround activity in that year. EPGI submitted the overtime expense in 1998 and 1999 was comparable as the level of turnaround activity was also comparable.

EPGI also noted that the FIRM Customers' argument did not take into account such factors as the impact of escalation on overtime and the impact of converting contract staff to permanent staff which would also increase reported overtime costs. EPGI submitted that it would experience more overtime for repairs and forced outages during years of tight supply in the Alberta marketplace which resulted in more work being done during off-peak periods such as weekends.

EPGI noted the FIRM Customers asserted:

> In the absence of any benefits related to severance in either of the two test years, we recommend the $0.2 million severance provision included in 1999 and 2000 salaries be disallowed. [21]

EPGI stressed this suggestion was without merit when considered in light of EPGI's evidence. EPGI stated this cost would cover the reasonable severance costs associated with terminations.[22] EPGI submitted the cost was a legitimate cost associated with operating a business. EPGI also testified that its actual severance costs in 1999 would be higher than the $0.2 million forecast.[23]

Board Findings

The Board expects EPGI/EPTI to ensure that proper checks and balances are in place within the budget process to limit the possibility of bias being introduced with respect to EPGI/EPTI's forecasts. Further, the Board, with the benefit of intervenor testing, has the ability and responsibility to ensure that forecasts approved for the test years are reasonable.

[21] FIRM Customers Argument, p.116
[22] Tr. p.433
[23] Tr. p.1458

The Board agrees with the FIRM Customers that the escalation rate applied to the category results in a rate higher than the 3.2% escalation as filed by EPGI. With respect to EPGI the Board considers that severance costs are a normal cost of operating a business and the amounts are based on past experience and are reasonable. The Board notes EPGI's evidence that actual 1999 severance costs will exceed $0.2 million. Accordingly, the Board accepts EPGI's forecast of severance costs to be reasonable.

The Board further considers that when the "at-risk" compensation is combined with the annual escalation of 3.2%, the resulting average increase for labour and salary for 1999 and 2000 is almost a 7% increase in each year. The Board adopts the view that the utility management has the responsibility for designing and implementing an employee compensation program consistent with the market conditions in which the utility operates subject to regulatory oversight. The Board considers that base compensation and at-risk compensation can reasonably be included as a cost recovered from customer rates. However, the Board considers the need for a 7% annual increase has not been demonstrated and the Board will reduce these amounts below.

The Board directs EPGI, in its refiling, to make the following changes:

- Reduce the labour portion by $0.25 million in 1999 and $0.50 million in 2000.
- Reduce the salary portion by $0.25 million in 1999 and $0.15 million in 2000.
- Reduce "at-risk" compensation by $0.2 million in 1999 and $0.15 million in 2000.

The Board will allow and approves the following as filed by EPGI:

- The additional $0.8 million for new positions and reclassifications in 1999.
- The decrease of $0.6 million for staff reductions in 2000.
- Overtime expenses in 1999 and 2000.
- Severance costs of $0.2 million in each of 1999 and 2000.
- Escalation, additional positions and vacancy fills for 1999 and the escalation for 2000.

The Board notes the cost of EPGI's incentive compensation is to be funded by any achieved savings or by shareholders.

The Board has summarized the adjustments to EPGI's labour, salary, overtime and "at-risk" compensation as follows:

EPGI Labour, Salary Overtime and At-Risk Compensation
Board Approved (1999 – 2000)
($million)

	1999			2000		
	As Filed	Board Adjustment	Board Allowed	As Filed	Board Adjustment	Board Allowed
Labour	9.72	(0.25)	9.48	9.65	(0.50)	9.15
Labour O/T	1.47		1.47	1.51		1.51
Salary	7.61	(0.25)	7.36	7.75	(0.15)	7.60
Salary O/T	0.16		0.16	0.14		0.14
At-Risk	0.65	(0.20)	0.45	0.65	(0.15)	0.50
Incentive	0.00	0.00	0.00	0.00	0.00	0.00
Total	19.61	(0.70)	18.91	19.70	(0.80)	18.90

Accordingly, the Board directs EPGI, in its refiling to reduce labour, salary and "at-risk" compensation by $0.7 million in 1999 and $0.8 million in 2000.

With respect to EPTI the Board notes that no Intervenors provided argument on the compensation program respecting the costs forecast for 1999 and 2000. The Board has reviewed the costs and accepts the wages/salary and inflation as filed. The Board, however, finds that the increase to the "at-risk" compensation is more than twice the amount forecast for 1998 or actually paid in 1997. The Board considers that the need for the increase has not been demonstrated and, therefore, the Board directs EPTI, in its refiling, to reduce the "at-risk" ompensation by $0.1 million in each of 1999 and 2000.

The Board has summarized the adjustments to EPTI's wages, salary and "at-risk" compensation as follows:

($million)

	1999			2000		
	As Filed	Board Adjustment	Board Allowed	As Filed	Board Adjustment	Board Allowed
Wages/Salary	2.96		2.96	3.00		3.00
Inflation	0.06		0.06	0.06		0.06
At-Risk	0.23	(0.10)	0.13	0.25	(0.10)	0.15
Incentive	0.00		0.00	0.00		0.00
Total	3.25	(0.10)	3.15	3.31	(0.10)	3.21

The Board expects that salary charge-outs and fringe benefits will be adjusted for both EPGI and EPTI accordingly when the above adjustments are made to the compensation program.

(d) Self-Insurance Reserve

EPGI proposed to continue its Self-Insurance Reserve (SIR) in 1999 and 2000.[24] EPTI did not propose a SIR for the transmission business unit during the two test years. [25]

The following table sets out the EPGI SIR continuity schedule based on modifications during the hearing.[26]

SIR - EPGI
(as filed)

	1997 ($ million)	1998 ($ million)	1999 ($ million)	2000 ($ million)
Opening balance	1.000	0.250	0.500	0.750
Add to reserve	0.000	0.250	0.250	0.250
Claims	(0.750)	(0.000)	(0.000)	(0.000)
Closing balance	0.250	0.500	0.750	1.000
Mid-year balance	0.625	0.375	0.625	0.875

Source: EPGI Evidence, Schedule G-13, Tr. p.260

The last time EPGI SIR funds were used was in 1997.[27] The claim was for $750,000, being the amount of the insurance deductible associated with the Clover Bar 3 transformer incident.

Position of EPGI

In 1999 and 2000, EPGI proposed to add $250,000 per year to the reserve, for a total of $0.5 million. EPGI did not forecast any claims during these two test years. Consequently, the balance at 31 December 2000, was forecast to be $1.0 million. EPGI suggested the balance in this account might later be returned to customers through the Balancing Pool.

Position of the FIRM Customers

The FIRM Customers considered the proposed $250,000 per year contribution to the reserve as reasonable in view of EPGI's stated policy of attempting to restore the level of the reserve over a three year period. The FIRM Customers also agreed that EPGI's target level of $1.0 million was consistent with the Board's 1996 GTA decision.[28]

[24] EPGI Evidence, Schedule G-13
[25] Tr. p.262
[26] Tr. p.260
[27] ~~EPGI~~ EPGI-13
[28] Decision U97065, p. 423

With regard to returning the SIR balance to customers, the FIRM Customers agreed the Balancing Pool proposal had merit and suggested the Board make this a direction in its Decision.. The FIRM Customers suggested this reconciliation should be done in conjunction with all other accounts requiring a truing up at the end of 2000. The FIRM Customers stated that customers did not want to pay for insurance through the PPA process and also have an unspecified disposition of the SIR balance lingering with EPGI when generation was deregulated and the opportunity for recovery of generation related costs was limited.

Board Findings

The Board accepts EPGI's position that the self-insurance reserve be continued for the 1999 and 2000 test years.

The Board, in the section of this Decision dealing with AE's Reserve for Injuries and Damages, determined the Reserve shall not be charged with UOV payments for any events subsequent to 1 January 1999. Applications for relief of UOV payments shall be made via the TSR mechanism. This same direction would apply to EPGI. EPGI has the opportunity to make a TSR Application to cover such losses.

The Board directs EPGI, in any application for a TSR, to include adjustments that are consistent with the methodology approved by the Board in the section of this Decision dealing with AE's Reserve for Injuries and Damages.

The Board directs EPGI to apply to the Board for final disposal of the closing balance of the self-insurance reserve as at 31 December 2000. At the time of the application, the Board will review the charges to the self-insurance reserve and approve the disposition of any remaining balances to the Balancing Pool.

(e) Hearing Cost Reserve

EPGI proposed an annual provision of $350,000 for 1999 and 2000 with a balancing provision of $331,000 in 2000 to the Hearing Cost Reserve. EPGI forecast that the balance would be zero as of 31 December 2000.

1. GENERAL
(e) Hearing Cost Reserve

The following table sets out the Hearing Cost Reserve Continuity Schedule supplied by EPGI in the Application[29]

	1998 ($ 000)	1999 ($ 000)	2000 ($ 000)
Opening balance	(787)	(531)	(681)
Reserve provision	800	350	350
Balancing provision			331
Charges	(544)	(500)	0
Closing balance	(531)	(681)	0
Mid-year balance	(659)*	(606)	(340)

* The Board has corrected the mid-year value for 1998 from the amount of $859,000 shown on the Schedule at line 45.

EPTI did not propose that a Hearing Cost Reserve be established.

Position of the Intervenors

Intervenors did not address EPGI's proposed annual provisions for the Hearing Cost Reserve.

Position of EPGI

EPGI set out a recommendation for reconciling residual amounts in accounts such as the hearing cost reserve.

EPGI explained the first issue was to determine the amount of any adjustment and the process for agreeing to what the adjustment should be. The second issue was the recovery mechanism and the period over which the adjustment should be collected.

EPGI viewed that any adjustments associated with 1999/2000 should be approved by the Board. Interested parties should first attempt to settle on the adjustment amount, if any. If agreement could not be reached, the adjustment would be determined through the Board's usual process.

In the case of the Hearing Cost Reserve account, EPGI stated the required adjustment should be known by mid-2000 with some certainty. For activity that might occur beyond mid-2000, EPGI suggested a forecast of the adjustment could be made, allowing sufficient time for the entitled DISCOs to reflect the adjustment in retail rates.

[29] EPGI Evidence, Schedule G-14, p.S-20

Board Findings

The Board agrees with EPGI that the annual provision of $350,000 for 1999 and 2000 and the balancing provision of $331,000 for 2000 are appropriate and that the resulting forecast balance of zero is reasonable as of 31 December 2000. The Board notes that the total provision for 1999 and 2000 is $1,031,000. The Board, in the interests of rate stability, considers it would be more appropriate to average the total provision for each of the test years. Accordingly, the Board directs EPGI, in its refiling, to include a hearing cost provision of $515,000 for 1999 and $516,000 for 2000.

The Board also considers that it is appropriate to establish a Hearing Cost Reserve for EPTI as of 1 January 2001.

The Board notes EPGI's proposed method of dealing with any outstanding balance in the hearing cost reserve by using an adjusting balancing provision in 2000 to effect a zero balance at year end and notifying the DISCOs accordingly. However, the Board considers that the most simple and practical approach is to transfer any positive or negative balance to the newly established EPTI Hearing Cost Reserve. Accordingly, the Board directs EPGI to transfer any residual balance, whether positive or negative, in the EPGI Hearing Cost Reserve at the end of 2000 to the EPTI Hearing Cost Reserve.

(f) Y2K

EPGI/EPTI proposed to capitalize all capital and operating expenses directly attributable to EPGI/EPTI's Y2K Project. EPGI/EPTI stated that all costs incurred in 1998 and 1999 would be held in CWIP accounts and added to rate base in 2000. EPGI/EPTI indicated that this treatment recognized that these costs were unusual, only benefited years 2000 and beyond, and were to be recovered over time.

Intervenors did not provide evidence or take issue with EPGI/EPTI's proposal to collect and recover Y2K costs.

Position of EPGI/EPTI

EPGI/EPTI suggested the proposed treatment to capitalize all capital costs and operating expenses was similar to that agreed to in the 1998 Negotiated Settlement with interested parties.

EPGI/EPTI stated the capitalized Y2K costs included direct project costs and costs allocated to the Corporation respecting EPCOR's testing and remediation work on corporate business applications, and EPCOR's Project Management Office (PMO) which provided overall management and administration to the Y2K project. EPGI/EPTI stated both types of allocated EPCOR costs were based on the individual business unit's Y2K expenditures proportional to the total Y2K expenditures of all business units in the EPCOR group. EPGI/EPTI submitted that the

capitalized Y2K costs would be recovered over the life of the particular assets to which the costs were related.

EPGI stated that the total costs to be capitalized in 2000, related to the Y2K program, was $12.6 million which included the direct project costs of $9.2 million plus the allocated costs of $3.4 million as per Tables 1 and 2 in CCA-EPGI-17. EPGI submitted that the FIRM Customers had incorrectly stated that EPGI's Y2K costs were approximately $10 million. EPGI indicated that allocated costs associated with Y2K compliance of $3.4 million should be included to bring the total costs for 1998, 1999 and 2000 to $12.6 million.

Position of the FIRM Customers

The FIRM Customers acknowledged the need for EPGI/EPTI's Y2K capital additions in 2000 as being beyond the normal scope of typical capital additions. The FIRM Customers stated that EPGI's total forecast amount to be capitalized in 2000 was approximately $10 million.

Board Findings

The Board notes that the Intervenors did not file any evidence to challenge the prudence of EPGI/EPTI's Y2K program, the costs incurred and forecast or the proposed amortization period of those costs.

The Board accepts EPGI/EPTI's costs and the proposed methodology of amortizing the costs over the life of the asset to which the costs relate as a reasonable and fair treatment. The Board directs EPGI/EPTI, in their refilings, to capitalize the Y2K costs to rate base in 2000 and to amortize those costs according to the asset for which the Y2K costs were incurred.

(g) Return on Decommissioning Reserve

The annual depreciation expense charged to customers is made up of the following two components:

- The original cost of the asset allocated over the service life of the asset.
- The forecast future net salvage (i.e. gross salvage less cost of removal) allocated over the service life of the asset. (Note: for generating plant, the forecast net salvage is negative for all accounts and is referred to as the decommissioning cost. For transmission plant, the forecast net salvage is negative for most accounts although some accounts, such as transmission cable in underground ducts, may be positive.)

It is important to note that the first component of the annual depreciation expense represents a return of the capital invested in utility assets by the owner.

The second component, future net salvage, consists of two parts. The future negative net salvage represents funds supplied by customers through an additional charge to the annual depreciation

expense and a future positive net salvage which represents funds supplied by the owner through a reduction to the annual depreciation expense. The net of the future positive and negative net salvage amounts is referred to as the decommissioning reserve.

The total accumulated depreciation expense which consists of both components, annual depreciation and future net salvage, is deducted from the original cost of the asset in determining the rate base for a regulated utility. The effect of deducting the second component from rate base is to provide any customer-supplied funds and any owner supplied funds a credit equal to the allowed composite rate of return.

EPGI/EPTI proposed a segregation of the accumulated depreciation into the above noted two components as had been recommended by Foster Associates as follows:

> Foster Associates, however, is recommending a change in the recording of interim net salvage and future dismantlement costs that represents a departure from the current practice of Edmonton Power Generation Inc. and Edmonton Power Transmission Inc. The Companies are currently accruing for interim net salvage and future dismantlement costs as a component of the primary account depreciation rate. This treatment produces a commingled depreciation reserve in which reserve imbalances created by net salvage parameters cannot be separated from imbalances created by service life statistics. Stated differently, the portion of the depreciation reserve attributable to net salvage cannot be isolated from the portion attributable to the allocation of the original cost of plant and equipment to operations. It is the opinion of Foster Associates that accounting for salvage and removal expense can be improved and simplified by establishing a separate accrual rate for net salvage at the function level (or by major plant locations) and maintaining an associated net salvage reserve. The benefits of this treatment include improved monitoring of the adequacy of the estimated net salvage rates and elimination of the need to identify net salvage proceeds by primary plant account.[30]

EPGI proposed to pay customers a credit in respect of EPGI's forecast mid-year decommissioning reserve balance in 1999 and 2000 based on a commercial investment rate of 4.76%.[31] EPGI calculated a credit of $2.7 million in 1999 and $3.1 million in 2000 which the Board notes is at an investment rate of approximately 5.20%. The credit received by customers under current regulatory practice would be $5.5 million and $6.4 million for 1999 and 2000 based on the composite rate of return of 10.6%. Consequently, the effect of EPGI's proposal is to increase charges to customers by $2.8 million and $3.3 million in 1999 and 2000.[32]

[30] EPGI Evidence, Appendix B, p.6
[31] EPGI Application, p.7
[32] EPGI Evidence, Schedule G-23

EPTI proposed a credit of $0.2 million for each of 1999 and 2000. The credit received by customers under current regulatory practice would be approximately $0.4 million in 1999 and 2000. Consequently, the effect of EPTI's proposal is to increase charges to customers by $0.2 million in 1999 and 2000.[33]

EPGI considered it was no longer reasonable for EPGI to pay a credit to customers on its decommissioning reserve at the composite rate of return for the following reasons:

- Calculating the credit based on EPGI's composite rate of return assumes that EPGI is able to generate investment income at that rate. EPGI's evidence shows that EPGI is a dying corporation with limited investment opportunities.[34] Exhibit 57 shows that EPGI's ongoing capital additions decline steadily over the PPA period and are below the projected annual depreciation expense. In these circumstances, EPGI considers it to be unfair and unreasonable for the Board to require EPGI to continue crediting customers on the decommissioning reserve as though EPGI is in a position to invest the funds to yield a return at or near the level of EPGI's composite rate of return on an ongoing basis.

- EPGI's composite rate of return reflects the investment risks of the shareholder and bondholders. Crediting customers at this rate is inappropriate as customers are not bearing any investment risk in relation to the decommissioning reserve. Customers are not affected if earnings fall short, while EPGI's shareholder certainly is at-risk. It is unreasonable and unfair for customers to be compensated for risks they are not taking.[35] As explained by Mr. Vaasjo:

  > Whereas, going through the calculation as it exists now, where you get a credit equal to the weighted average cost of capital, there is nothing at-risk. To the extent that EPGI over-performs or under-performs or whatever, the customer is not at-risk whatsoever.[36]

As EPGI's plants age, the sums collected for the decommissioning reserve are becoming sizable and, therefore, it is timely that an appropriate investment rate on the balance of the reserve be established. Otherwise, as its plants age, EPGI may be placed in the nonsensical position of finding itself paying out money to run certain units (e.g. Rossdale) with no reasonable opportunity to invest in anything paying better than a commercial investment rate.

EPGI indicated that, if the Board so directed, it would be prepared to create a funded reserve and appoint a fund manager to manage the reserve on behalf of customers. Customers would be credited with whatever amount the fund earned which, in EPGI's submission, would be in line

[33] EPTI Evidence, Schedule T-20
[34] ENMAX-EPGI-23(a); Tr. p.819
[35] ENMAX-EPGI-23(c)
[36] Tr. p.529

with the commercial investment rate proposed by EPGI in its Application. EPGI noted, however, that the earnings on such a funded reserve would likely be taxable with the result that customers would end up receiving a lower net credit than under the approach proposed by EPGI. As Mr. Vaasjo explained, the Company is serious about this issue and will establish a funded reserve if directed by the Board to do so:

> Well, as I say, the company is concerned enough about this that they would be willing to set up a fund. However—and just to be clear—if we established a fund, the cost to the customer would be increased in the event that we ever became taxable, because that, then, is a taxable income. It's not just a netting process, so what the customer would be receiving as a credit would be equivalent to half of what otherwise would have been earnings on the fund.[37]

EPGI submitted that its proposal to calculate a credit to customers in respect of the decommissioning reserve at a commercial investment rate is reasonable given the unique circumstances of EPGI. In the alternative, EPGI requested that the Board direct EPGI to establish a funded reserve.

Position of the FIRM Customers

The FIRM Customers stated EPGI's proposal was inconsistent with other Utilities. When the FIRM Customers asked why EPGI would not invest in rate base, EPGI noted that there was a significantly declining rate base over the foreseeable future. The FIRM Customers indicated that EPGI was influenced by the PPA world that they will be entering in 2001 and beyond. The FIRM Customers have previously indicated that it was inappropriate to base 1999 and 2000 on PPA considerations since there will be plenty of time and another forum for that. The FIRM Customers submitted there was no reason to ratchet future circumstances back into 1999 and 2000.

The FIRM Customers suggested EPGI failed to acknowledge approximately $44 or $45 million of customer-supplied funds already invested and effectively reducing rate base, for which EPGI did not need to seek out investment opportunities. The FIRM Customers stated that EPGI suggested its capital expenditures were declining and were below the annual depreciation expense. The FIRM Customers submitted EPGI, was not only mixing recovery of capital investment with decommissioning funds, but also ignored the future refinancing requirements.[38]

Position of ENMAX

In ENMAX's view, it was both fair and equitable that the past treatment of the decommissioning reserve be continued. ENMAX submitted the those who have paid, are paying and will pay for power produced by EPGI and EPTI have contributed to the decommissioning costs. Under the method of regulation in place when these funds were paid to EPGI and EPTI, ENMAX

[37] Tr. p.529

[38] EPGI Evidence, Schedules G-6 and G-7

suggested there was an anticipation that these funds would reduce the amount required to be invested and there would no longer be a request for a return on these funds. ENMAX submitted this expectation provided an equitable trade off—customers had paid for an expense prior to the utility being required to expend the funds, but received a credit because there was less investor-supplied capital required.

ENMAX stated EPGI/EPTI's witnesses attempted to suggest that the proposal was not a departure from the current practice[39] by stating that the historical method of calculating return on rate base would not be disturbed. Instead, EPGI/EPTI would give themselves a credit based on the difference between the weighted average cost of capital and the 4.76% rate that EPGI/EPTI believed customers should earn on their money. ENMAX stated that EPGI/EPTI proposed a fundamental change in the treatment of the decommissioning reserve which provided EPGI with an extra $3.0 million in 1999 and $3.5 million in 2000[40] and EPTI with an extra $200,000 in each year.[41]

ENMAX asserted that the net effect of the EPGI/EPTI proposal would be to have EPGI/EPTI earn a return on capital that had not been supplied by its investors, but rather by its customers. ENMAX suggested that EPGI/EPTI accomplished this return by proposing that customers should get the equivalent of short term debt cost on contributed capital while EPGI/EPTI received the weighted average cost of capital which included an equity return on their money. ENMAX submitted that the net effect would be for EPGI/EPTI to earn a markup on the funds contributed by customers as determined by the calculation in Exhibit 28.

ENMAX stated there were several factors wrong with the EPGI/EPTI proposal:

1. The current regulatory model compensated investors and EPGI/EPTI for the funds that they have invested. This concept goes back to the early 1920's.[42]

2. Any funds provided were not specifically segregated or identifiable. As such EPGI/EPTI have complete freedom to use the funds provided as they saw fit.

3. Even if the funds were segregated, there was no reason why the entitled DISCOs should receive a lower rate of return than the shareholders. To propose that the end users of the power should only get a short-term debt rate of return, and then argue that the same individual, as an investor, needs 11% on equity investment was highly inconsistent.

4. Now, less than two years prior to deregulation, was not the time to unravel 75 years of regulatory precedent.

---

[39] Tr. p.521-522

[40] Exhibit 28

[41] EPTI Application, p.11

[42] See *Bluefield Water Works & Improvement Co.* v. *Public Service Commission of West Virginia* (262 U.S. 679, 1923); and *Northwestern Utilities Ltd.* v. *Edmonton* (1929) SCR 186 (SCC)

ENMAX recommended that the decommissioning funds, contributed by customers prior to those costs being incurred, should be treated as a deduction from rate base. ENMAX recommended the add-on proposed by EPGI/EPTI should be disallowed.

ENMAX submitted that the Board did not have enough information to direct EPGI to establish a funded reserve. ENMAX suggested the information currently on the record provided for the recovery of decommissioning costs on the assumption that the reserve did not accrue any income. If the Board were to direct EPGI to establish a funded reserve, ENMAX recommended that the amounts recovered through the revenue requirement should be adjusted in such a manner as to reflect amounts, similar to an annuity payment, so that the combined amount of principle plus earned income would provide EPGI with the appropriate decommissioning funds at the time of decommissioning.

ENMAX submitted that EPGI's argument, that EPGI could not earn a return equivalent to its weighted average cost of capital on the decommissioning reserve and, therefore, customers should not be compensated in the manner similar to the compensation received by the investors at EPGI, failed on two grounds:

1. The rate of return on common equity, provided to EPGI's shareholder, included compensation not only for the risks, but also for attracting capital. Customers have the same alternative investments available as the shareholder of EPGI and, therefore, need similar returns.

2. EPGI should be able to earn a yield near or equivalent to its weighted average cost of capital on an ongoing basis. Exhibit 129 indicated that the pension fund managers of TransAlta have been able to earn returns ranging from a low of 14.2% to a high of 19.9% over the last four years. This rate of return was in excess of EPGI's weighted average cost of capital; therefore, a prudent investment manager should be able to earn returns equivalent to EPGI's weighted average cost of capital. If not, EPGI's weighted average cost of capital was too high.

ENMAX submitted the concept behind treating the decommissioning costs as zero cost capital or a deduction from rate base, was for the utility to avoid the cost of financing those amounts with investor-supplied capital. ENMAX submitted that, if the Board were to adopt EPGI's approach, then the Board would have to recognize the enhanced return achieved by the shareholder as a result of the difference between the weighted average cost of capital and the proposed short term investment rate, and reduce the return on common equity accordingly.

With respect to the new alternate application included in EPGI's argument, ENMAX submitted that there was not enough information with respect to a funded reserve for Board approval. ENMAX suggested the reserve would have to be set up, and procedures would have to be established to ensure that EPGI did not receive a benefit between the time the funds were

received and when these funds were placed in the reserve. In addition, ENMAX stated procedures would have to be established to determine the level and the amount of expenditures for decommissioning costs that would be charged to the reserve, and a methodology for doing the same. ENMAX indicated that an independent trustee or manager would be required to ensure that EPGI was not receiving an additional benefit from the funds. Since none of these items were discussed or considered during the hearing, ENMAX submitted it would be premature and inappropriate for the Board to approve a funded reserve for decommissioning costs in this decision. ENMAX suggested that if EPGI had seriously considered this proposal, it would have brought forward all of this information in its application nine months ago.

Position of EPGI/EPTI

EPGI submitted that the suggestion it would somehow "earn a markup" on the decommissioning reserve funds was wrong. EPGI suggested that "markup" in this context was the difference between a risky investment return (e.g., rate of return on rate base) and the risk-free commercial investment rate (i.e., the 4.76%).

EPGI stated there was no available "markup". EPGI is a dying company with limited investment opportunities.[43] As shown on Exhibit 57, EPGI's capital additions generally decline over the 2001-2020 PPA period and that in each of those years depreciation funds will be more than sufficient to offset capital expenditures. EPGI submitted that ENMAX did not challenge EPGI's evidence respecting the "non-availability" of investment opportunities.

EPGI stated the quantification of any "markup" must consider not only the hoped-for returns but also the risks to which the fund was exposed and the party who would be exposed to the risks. EPGI defined the risks as either the returns could be insufficient or the capital could be lost. If EPGI collected the funds from customers and placed the decommissioning reserve "cash" in a risk-free investment, then there would be no risk to EPGI or its customers that the funds would not be available to offset future decommissioning expenses. No "markup" would be earned, and the credit that customers received would be based on no more than the risk-free rate.

Alternatively, EPGI stated if the decommissioning reserve "cash" was exposed to a risky investment—say, an investment in unregulated generating assets—then the question of whether EPGI or its customers were exposed to the investment risks of that investment become central to the question of who should receive the "markup." As explained by Dr. Bridgeman, "Part of the issue is that there's questions around who is investing in rate base; who is taking the risk..."[44]

EPGI submitted that a proper matching of risks and rewards required that the party assuming the risk should receive the "markup." EPGI should receive the "markup" unless customers were prepared to take the risks associated with that investment and provide additional funds in the future if the investments made on their behalf by EPGI yielded unsatisfactory returns.

[43] ENMAX-EPGI-23(a); Tr. p.819
[44] Tr. p.818

EPGI claimed ENMAX wanted the customer to receive the "markup" without being exposed to the risk.

EPGI suggested the entire matter of who was entitled to whatever "markup" might be earned could be resolved by a direction of the Board to establish a separately-financed, trustee-managed decommissioning reserve fund on behalf of EPGI's customers.[45]

EPGI's disagreement with ENMAX arises if the decommissioning reserve funds were retained by the utility and if those funds were then deemed to earn a return other than the risk-free rate (e.g., the rate of return on rate base). EPGI submitted the crux of the disagreement was that customers did not assume the risks of investors and were, therefore, not entitled to the rates of return earned by investors. EPGI asserted that customers paid rates for service; customers did not supply capital to the utility. EPGI concluded that customers were not exposed to the investment risks on the rates they paid for service.[46]

Mr. Vaasjo explained further:

> Typically an investment you make, you obtain a return on that investment; at some point in time, you can cash in the investment and get it back. You have principal at-risk. In this case, the customer is making no investment. There is no capital at-risk from a customer's standpoint. To consider this reserve to be a fund that is at-risk from a customer's standpoint, the way it is currently operating, is totally inappropriate.[47]

EPGI claimed ENMAX's conclusion that an "inconsistency" existed because the same electricity consumer could receive an 11% rate of return on equity as an investor and a lesser rate of return as a customer was incorrect. EPGI submitted that if the customer was risking capital and assuming the risks of an equity investor, then he would be entitled to the 11%. However, if the customer had not risked capital and was not assuming the risks of an equity investor, he would only be entitled to the commercial risk-free interest rate.

EPGI submitted ENMAX's failure to distinguish customers and investors became irrelevant if a segregated decommissioning fund was established whereby customers bore the risks, reaped the rewards and suffered the losses of investors.

Board Findings

The Board agrees with EPGI/EPTI's proposal to segregate the accumulated depreciation into two components with the second component referred to as the decommissioning reserve. The Board

[45] ENMAX-EPGI-23(b)
[46] ENMAX-EPGI-23(c)
[47] Tr. p.819

agrees that accounting for salvage and removal expense and monitoring of the adequacy of the estimated net salvage rates will be improved.

The Board does not consider it desirable for customers nor necessary to create a funded decommissioning reserve and appoint a fund manager to manage the reserve on behalf of customers. The Board considers that just and reasonable rates can be fixed by deeming an appropriate credit rate to the customer-supplied decommissioning funds.

The Board does not agree with EPGI/EPTI that the decommissioning reserve should be credited at a commercial investment rate. The Board has made this determination for the following reasons:

- Most of the decommissioning reserve customer-supplied funds for EPGI/EPTI may be used for decommissioning expenses or capital additions during the test years.
- The concerns expressed by EPGI respecting excess customer-supplied funds generally apply to the PPA period and do not manifest themselves in any material way during the test years.
- Funds supplied by customers may be retained by EPGI/EPTI for a considerable length of time before being required for their intended purpose.
- Relatively small differences in timing between when the customer-supplied funds are received and when the funds are used should not disadvantage customers for an extended period of time.
- There is no evidence that EPGI/EPTI, in reality, does not have the opportunity to exercise latitude in how the customer-supplied funds are actually used on a cash basis vs. their accounting treatment. There is no evidence, for example, that these funds will not be available for investment or operating cash for other regulated or non-regulated businesses.
- There is no evidence to demonstrate that in the hierarchy of risk associated with financing vehicles, the position of customer-supplied funds warrants the lower rate of return normally associated with the commercial investment rate. There is no evidence, for example, that customer-supplied funds would rank ahead of the security position of long term debt.
- There is no evidence that the length of time that EPGI/EPTI retains the funds, before being used for their intended purpose, is consistent with the length of time that a normal investor would deposit funds at a commercial investment rate.

Rather, the Board considers that there is no evidence that the customer-supplied amounts cannot be invested in other capital or operating purposes, which would warrant that the funds continue to be credited at the composite rate of return, given their security position and time available to the company.

The Board agrees with the FIRM Customers that the 31 December 1998 balance in EPGI's decommissioning reserve has already been invested in rate base assets. No investment

opportunities need to be sought out for this capital. The Board considers that this portion of EPGI's decommissioning reserve should continue to be credited at the Board allowed composite rate of return.

The Board notes that the majority of the $17.7 million of funds provided by customers for EPGI decommissioning for 1999 and 2000 can be used to finance the EPGI decommissioning expenditures forecast for 1999 and 2000. The Board is not persuaded that the residual excess during the test years is large enough to warrant a change to the current method of crediting customer-supplied funds with the composite rate of return. This residual may be a temporary timing difference that could easily be reversed in the year 2001. Should the timing difference not reverse the residual, for the reasons set out above, the Board is not persuaded that EPGI would be unable to achieve investment opportunities for this residual at a rate significantly different from the composite rate of return. The Board also considers it appropriate for the owners to continue to receive the composite rate of return on the owner supplied funds in the decommissioning reserve. Therefore, the Board considers that there should be no change to the current method of crediting both customer and owner-supplied funds with the composite rate of return for EPGI.

The Board notes that the $15.2 million of funds provided by customers for EPTI's depreciation expense (including the decommissioning reserve provision) are approximately equal to the $14.5 million in funds required for capital expenditures in 1999 and 2000. The Board has no evidence to suggest that EPTI will be unable to invest decommissioning funds in EPTI's rate base on an ongoing basis. Therefore, the Board considers that there should be no change to the current method of crediting customer-supplied funds with the composite rate of return for EPTI. Accordingly, the Board considers the entire balance for EPTI of $3.3 million in 1999 and $3.5 million in 2000 should be credited at the Board allowed composite rate of return.

The Board directs EPGI and EPTI, in their refilings, to continue to credit the decommissioning funds supplied by customers at the composite rate of return to reflect the above Board findings.

(h) Inflation Assumptions

Where EPGI/EPTI was aware of a specific increase that was likely to occur with respect to a particular cost at the time of preparing the 1999/2000 forecasts, EPGI/EPTI used that cost increase for forecasting purposes. In cases where EPGI/EPTI was not aware of such an increase, EPGI/EPTI prepared the forecast in 1998 dollars and then applied an inflation adjustment factor to determine the cost for 1999 and 2000.

EPGI/EPTI used an inflation adjustment factor of 1% for costs where EPGI/EPTI was not aware of a specific increase in 1999 and 2000. EPGI/EPTI stated this adjustment factor was reasonable having regard to the October 1998 Consensus Forecast dated 12 October 1998 wherein an adjustment factor of 1.6% was forecasted for 1999 and 1.7% for 2000.

1. GENERAL
(h) Inflation Assumptions

No Intervenor took issue with the inflation rate.

Board Findings

The Board considers that the method applied by EPGI/EPTI, for escalating forecast costs where specific increases were known, to be reasonable. The Board notes that Intervenors did not object to the method or the adjustment rate applied in general circumstances where future increases were unidentified. The Board accepts EPGI/EPTI's method of forecasting for known and available cost increases and the inflation adjustment factor of 1% where EPGI/EPTI was not aware of any specific increases during 1999 and 2000.

(a) Rate Base

(1) Capital Additions

EPGI's 1999 and 2000 capital additions are described in section 3.6.1.1 and Schedules G-20-1999 and 2000 (Summary of Rate Base Additions for 1999 and 2000) of EPGI's Application. EPGI's responses to a number of information requests and undertakings provide additional information respecting capital additions, including cost benefit analyses, condition assessments, etc. where appropriate (for example, MI-EPGI-16, FIRM-EPGI-26, 27, 28, 30, 31, ENMAX-EPGI-19, 27, 35, 36, 37, IPCAA-EPGI-44; Exhibits 23, 37 and 47).

EPGI's aggregate reservation price for 1999 and 2000 reflects forecast capital additions of $38.5 million and $52.7 million, respectively, as per Schedules G-20-1999 and 2000 in EPGI's Application, as adjusted by Attachment 3 to Exhibit 8.

Questions and concerns were raised with respect to the following aspects of EPGI's proposed capital additions:

- the level of EPGI's forecast capital expenditures for 1999 and 2000 compared to EPGI's historical capital expenditures and whether a portion of the proposed capital additions are related to "preparing for the competitive world";
- the need for the forecast capital expenditures relating to mine equipment refurbishment and replacement;
- the forecast maintenance and production improvement expenditures relating to EPGI's Clover Bar units;
- the status of and need for the Genesee black-start and Clover Bar black-stop generating projects;
- Rossdale decommissioning costs. (Note: The Board has concerns about EPGI's proposal to capitalize these costs).
- projects of less than $1 million;
- the 1992 Clover Bar IP rotor replacement and 1993 insurance claim.

These issues are discussed in detail in the sections that follow.

(A) Historical vs. Forecast Capital Expenditures Levels

Position of the Intervenors

The FIRM Customers submitted that it is difficult to refute the need for specific projects that EPGI can support with great detail. The issue from the perspective of the FIRM Customers is what is a reasonable level of capital additions given the history of forecasts and actual

experience. The FIRM Customers argued that reasonable test year trends could be extrapolated from historical data with appropriate consideration made for exceptional expenditures.

The FIRM Customers expressed concern with the level of capital expenditures being forecast by EPGI. The FIRM Customers claimed that the increased capital expenditures appear to be largely driven by the restructuring of the industry. To support their claim the FIRM Customers noted that this is the last chance under the existing regulatory regime to get all questionable costs covered off by customers before the PPAs come into effect and generation deregulation becomes a reality. Therefore, the FIRM Customers believed that EPGI is taking the opportunity to include an especially large number of questionable items in their forecast revenue requirements.

Additionally, the FIRM Customers stated that the Board's 1996 Decision provided a base for implementation of the EU Act. Customers reached agreement with EPCOR for 1997, negotiating significant reductions from the 1996 base. Similarly, the negotiated settlement for 1998 provided even further reductions in costs from 1997 negotiated levels. In contrast, for 1999/2000, EPGI is forecasting significant cost increases and capital additions. This led the FIRM Customers to the belief that EPGI is clearly trying to position itself for the post PPA time frame at customers' expense.

The FIRM Customers provided the table below to show that EPGI has forecast significantly higher capital additions than actually recorded for the years 1992 to 1997 and to demonstrate that forecast test year capital expenditures exceed the actual historical annual average.

	Forecast ($ million)	**Recorded ($ million)**	**Variance ($ million)**
1992	16.6	13.6	3.0 (18%)
1993	18.8	10.9	7.9 (42%)
1994	11.1	7.4	3.7 (33%)
1995	15.6	15.9	(0.3) (-2%)
1996	16.5	17.3[48]	(0.8) (-5%)
1997	27.1	17.9[49]	9.2 (34%)
1998 Re-forecast	62.8		
1999	28.7		
2000	47.5		

Source: 1992 to 1996 forecast - Decision U97065 p.396
1996 recorded to 2000 forecast from FIRM.EPGI-31

[48] This number shows as $9.75 million in Exhibit 20
[49] This number shows as $14.80 million in Exhibit 20

The FIRM Customers stated that since 1997 and 1998 were negotiated settlement years, they were not sure of the nature of the underlying negotiations or the basis for the forecast numbers for those years. However, they included these years for comparative purposes. The FIRM Customers noted that the average actual expenditure level was $13.8 million for the 6 years, peaking in 1997 at $17.9 million. They further noted that EPGI's forecasts for both 1999 and 2000, shown in ENMAX's Exhibit 20, significantly exceed these historical levels.

The FIRM Customers submitted that the Board needs to carefully consider the proposed projects and their timing when dealing with some of these requested increases in capital expenditures. The FIRM Customers recommended that the Board take into account the historical trend noted above when deciding the appropriate capital additions for the test years.

Based on these trends, the FIRM Customers suggested the expenditures for 1999 and 2000 should not exceed $20 million per year. In 2000, they recognized the need for Y2K capital additions as outside the normal scope of capital additions and noted that, in EPGI's Schedule G-20-2000, Y2K expenditures amounted to approximately $10 million. Therefore, the FIRM Customers proposed that the level of capital additions for 2000 be raised to $30 million to reflect this amount. Even though the FIRM Customers recommended expenditure levels would be significantly less than EPGI's forecast, the FIRM Customers believed that their proposal represents a reasonable and fair level of additions for EPGI over the two test years.

ENMAX was skeptical of EPGI's ability to accurately forecast future capital expenditures. ENMAX, like the FIRM Customers, also compared historical and forecast expenditure levels. It noted that, in ENMAX's exhibit 20, EPGI's actual capital additions for the period 1992-1997 averaged $12.05 million each year, a figure that is significantly different to the average for the forecast period 1998-2000 of $44.7 million per year. ENMAX stated that even if the $16.4 million in major spare generating parts that formed part of the negotiated settlement for 1998[50] were removed, the resulting average for 1998-2000 would still be $39.2 million. This, ENMAX submitted was excessive.

In addition, ENMAX noted that EPGI filed information in response to IPCAA-EPGI-1 about forecast expenditures from 2001-2010 and subsequently retracted it. The forecast was replaced with information that EPGI provided after the 30 October 1998 filing date, which showed that EPGI expects expenditures for the 2001-2010 period to be in the neighbourhood of $25-30 million annually. ENMAX submitted that based on past experience that forecast is likely to be high and indicated that there is a reference to that effect at page 396 of Board Decision U97065. In 1996 the forecast capital additions for EPGI (or its predecessor) were $16 million while the actual were $9.75 million.[51]

[50] Tr. p. 382
[51] Tr. p.388

ENMAX argued that, even though EPGI submitted that its forecast accuracy on capital additions has improved,[52] there has been no objective test of this contention. Consequently, ENMAX proposed that the Board apply a 25% negative contingency to EPGI's capital additions. It stated that the need for this negative contingency could also be demonstrated from a review of specific forecasted project expenditures.

Position of EPGI

EPGI noted that Intervenors chose not to lead any evidence of their own to challenge the prudence of EPGI's proposed capital additions. Instead, they asked numerous information requests and conducted extensive and detailed cross-examination with respect to a number of EPGI's proposed capital additions.[53] Additionally, they only chose to make submissions in final argument with respect to a small number of projects.

EPGI submitted that it has provided substantial evidence with respect to each project, which clearly demonstrated that each forecast capital addition is prudently incurred. EPGI contended that this evidence is more compelling and reliable in determining the question of prudence than comparing forecast to historical figures.

EPGI argued that, while purportedly based on EPGI's historical forecast and actual results, the FIRM Customers' suggestion that EPGI's total forecast capital additions be reduced to $20 million in 1999 and $30 million in 2000 is actually arbitrary. It also noted that ENMAX provided no basis, evidentiary or otherwise, for its 25% "negative contingency" but rather appeared to pull the number out of the air.

EPGI submitted that its forecast total capital additions for 1999 and 2000, on a normalized basis, are not materially different from actual for previous years or subsequent years' forecasts. It noted that there are a number of capital additions forecast for 1999 and 2000 that are unique to those years.[54] These include dismantling work at Rossdale in 1999 ($12 million) and Y2K related additions in 2000 ($12.6 million). EPGI further submitted that a comparison of increased capital requirements in 1999 and 2000 compared to prior years must also take into account the following:[55]

- Genesee unit 1 being put into rate base in 1995.
- Increased capital requirements for EPGI's gas units and the increased cycling they have been subjected to.
- Increased capacity factor for EPGI's Clover Bar units which has increased operating hours and, thus, wear and tear and capital requirements.

[52] Tr. p.393
[53] Tr. p.306-Tr. p.389; Tr. p.1050-1053
[54] Tr. p.384
[55] Tr. p.381 and p.386

EPGI stated that the evidence clearly demonstrates that its forecast capital additions are required and are prudently incurred for the purposes of the 1999 and 2000 test years. The additions are driven by turnaround work that is reasonable and must be done. Therefore, there is no basis upon which to conclude that EPGI's capital additions are somehow driven by the upcoming industry restructuring, as was suggested by some Intervenors.

Board Findings

The Board agrees with the Intervenors that, in assessing the need for and prudence of EPGI's capital expenditures, there should be regard for historical trends adjusted for unique circumstances. The Board considers the trending approach to be a good starting point that produces a coarse measure, which needs to be supplemented with a closer assessment of each major forecast addition. In this regard, the Board accepts EPGI's position that examination of each forecast addition is more reliable in terms of assessing need and prudence.

The Board notes that from the table provided by the FIRM Customers, it can be inferred that, on average, EPGI has over-forecast capital expenditures by approximately 20% over the period 1992-1997.

The Board will review the evidence respecting each forecast addition at issue and will render its decision in respect of that forecast expenditure. The Board notes that the test years represent a period when unique expenditures are being proposed (e.g. Rossdale Decommissioning, Y2K projects) requiring the Board to take this into account in its assessment of need and any comparison with historical trends.

(B) Mine Related Capital Expenditures

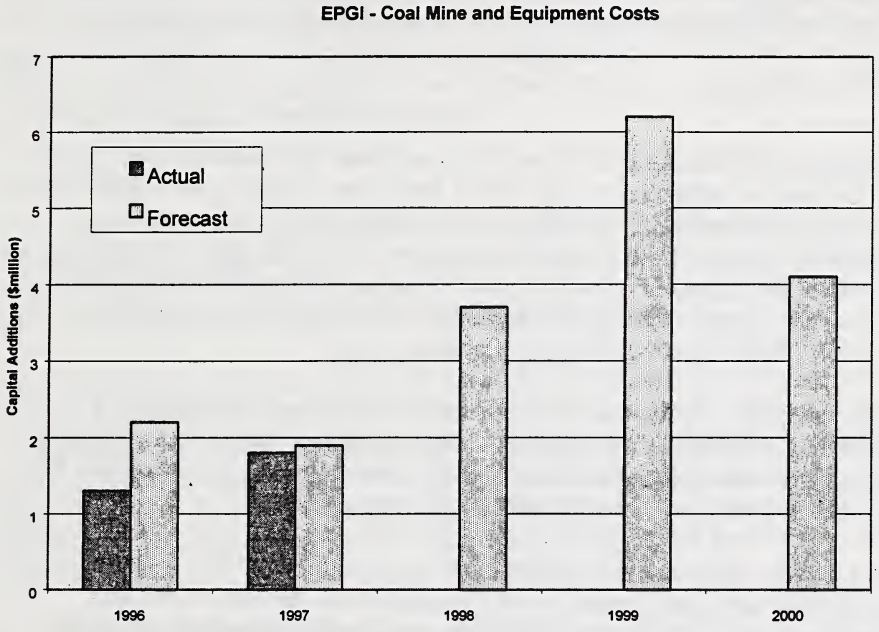
EPGI requested mining related capital additions of $6.2 million and $4.1 million for 1999 and 2000 respectively. Details are provided in ENMAX-EPGI-35 and 36. Exhibit 23 provided details respecting the M8750 dragline bucket rebuilds. Additionally, under cross-examination, Mr. Topping stated that of the $3.1 million in Heavy Equipment expense proposed for 1999, $1.0 million is for a large loader.[56]

Position of the Intervenors

The FIRM Customers provided the following chart to illustrate that the requested expenditures represent significant increases in cost relative to previous years.

[56] Tr. p.348, l.1

2. EPGI
(a) Rate Base



Source: FIRM.EPGI-28

The FIRM Customers submitted that the majority of these cost increases appear to be related to Heavy Mining Equipment ($3.1/$6.2 = 50% in 1999 and $2.4/$4.1 = 59% in 2000).[57] During cross-examination Mr. Topping indicated that the majority of these costs were for re-builds and not replacements.

The FIRM Customers noted that in ENMAX-EPGI-35 (b)(iv), a request was made to provide the in-service dates, associated depreciation rates and net book value at the time of replacement for each piece of equipment. The requested information was not provided.

It was the FIRM Customers' view that the timing and level of the expenditures are highly questionable on the eve of deregulation and that insufficient evidence was provided to support the expenditures requested. Accordingly, the FIRM Customers proposed that the mine related capital expenditures for 1999 and 2000 should be set at a level consistent with previous years and recommended an upper limit of $3 million per year.

[57] ENMAX.EPGI-35 (b)(i)

ENMAX also questioned capital additions relating to draglines and other heavy equipment but made no specific suggestions in argument as to what, if anything, should be done about these expenditures.

Position of EPGI

EPGI noted that in response to ENMAX-EPGI-35 and 36, it provided the in-service dates for all the major equipment that is to be replaced or rebuilt. EPGI stated that it groups mine capital into a single account known as "Genesee Mine." As with all other Genesee asset accounts, the Genesee Mine account is an Average Year of Final Retirement account. The depreciation rate applicable to the Genesee Mine account is set out on page 12 of the 1999 and 2000 Technical Updates. EPGI's approach to recording and depreciating the Genesee Mine account for the purposes of the 1999/2000 GTA is consistent with its previous filings.

EPGI noted that Mr. Topping misspoke himself when he stated that the majority of the $3.1 million expense for 1999 is for rebuilds. The majority of the expense is in fact for replacements, as indicated by Dr. Bridgeman when he stated that 1999 marks the eleventh year of operation for a number of critical pieces of mine equipment that will require replacement.

Mr. Topping explained that the dragline swing system work was comprised of the rebuilding/ replacement of gearboxes that have deteriorated. He also explained that the M8750 dragline bucket rebuilds are required every 5,000 operating hours due to degradation in the bucket lining caused by mining coal. Mr. Topping submitted that these projects are required to maintain current dragline availability.

The refurbishment/replacement of heavy equipment at the Genesee mine referred to in Schedules G-20-1999 and 2000 was set out in detail in response to ENMAX-EPGI-35. Mr. Topping beginning at Tr. p.347 provided additional information. As stated on Schedules G-20-1999 and 2000, the mine equipment projects are part of regular mine operating practice and are vital to the ongoing operation of the mine. As such, these projects are clearly necessary and their costs are prudently incurred.

EPGI submitted that there is no evidence on the record of this proceeding, which demonstrates that EPGI has somehow tried to inflate its mine capital additions for 1999 and 2000 on the "eve of deregulation." EPGI stated that it is a well-documented fact that mine capital costs are cyclical and fluctuate from year to year. It cited as an example, the cash flow provided in Appendix G to EPGI's Application for the Genesee mine from 1995 to 2028 that shows the cyclical nature of mine capital expenditures. Additionally, the 1994 EEMA filing shows clearly that mine capital costs fluctuate from year to year with peaks and valleys occurring frequently and inconsistently.[58]

[58] Exhibit 35A,Table C, 1994 EEMA Forecast proceeding

EPGI submitted that it filed information which shows that 1999 and 2000 coincide with both the 11-year operating life of various pieces of equipment purchased in 1988 and the 35,000 hour major maintenance interval for both Genesee draglines.[59] EPGI submitted that this clearly demonstrates that EPGI's applied-for mine capital additions are required in 1999 and 2000 and that the expenditures are prudently incurred.

Board Findings

The Board notes that the graph provided by the FIRM Customers clearly demonstrates that EPGI is forecasting significant increases in mine equipment expenditures in 1999/2000 relative to previous years. However, as noted previously, this trend must be interpreted and assessed in light of the specific circumstances surrounding these expenditures.

Based on the information provided in ENMAX-EPGI-35 and 36, the Board accepts EPGI's evidence that the test years represent a time in the mine equipment life cycle when critical pieces of mine equipment need to be replaced and when the Genesee draglines will require a major overhaul. Therefore, the Board would expect expenditures in these years to be significantly higher than in previous years. The requested expenditures appear reasonable to the Board. Accordingly, the Board will allow the requested mine equipment expenditures into the rate base of EPGI.

(C) Clover Bar Capital Expenditures

EPGI's Application contained a number of capital projects for Clover Bar aimed at enabling maintenance or improvement in production. In 1999, these include boiler repairs ($3.7 million), turbine repairs ($2.8 million), electrical switchgear and control systems ($2.2 million) and the replacement of the Unit 1 generator transformer ($2.0 million) for a total of $10.7 million.[60] In 2000, digital control systems, Unit 1 condenser tube replacement, Unit 1 feed water heater replacement, Y2K and asbestos removal projects totaling $10.9 million are forecast.[61] Additional details are also contained in FIRM.EPGI.31 and ENMAX.EPGI.35.

Position of the Intervenors

The FIRM Customers submitted that it is difficult for Intervenors to test the need for the maintenance and production improvement projects proposed for Clover Bar. They were of the view that these expenditures should improve the performance of the Clover Bar generators and stated that, to the extent the Board approves this level of expenditure for Clover Bar, the improved productivity should be recognized in the generation modeling. The FIRM Customers said that this would be particularly important should the Board not accept their recommendations concerning generation related deferral accounts as discussed in section 2.2 of their argument.

[59] Undertaking at Tr. p.405 (Exhibit 37)
[60] Exhibit 2; Schedule G-20-1999
[61] Exhibit 2; Schedule G-20-2000

ENMAX questioned the increase in forecast boiler repairs at Clover Bar in 1999.[62] ENMAX noted that the responses to FIRM.EPGI.31 and ENMAX.EPGI.35 revealed that EPGI forecast expenditures for Clover Bar will be $14 million in 1999 and $6.2 million in 2000. ENMAX suggested that these amounts must be contrasted with the last tested examination of Clover Bar additions in 1996 when additions were $2 million. It noted that notwithstanding the significantly higher additions, it was EPGI's position that the repairs will merely maintain the current plant reliability, not improve it.[63]

ENMAX also raised questions about EPGI's policy for replacing equipment, which it asserted, could lead to excessive forecasting.[64] ENMAX cited the Clover Bar Unit 1 generator transformer expenditure as an example. ENMAX noted that EPGI did a condition assessment study of the transformer in November 1997 that suggested the likely remaining life to be 3-6 years. Based on the response to ENMAX.EPGI-35(a), ENMAX concluded that the minimum life would be November/December of 2000. ENMAX further noted that achieving only one to two months beyond the minimum life would delay the need for additional expenditure beyond the test years. However, because EPGI's policy is to take action to mitigate risk once a problem is identified, which in this case would be the random failure of the transformer, it appeared to ENMAX that the minimum life is the *de facto* standard to which replacements are judged.

ENMAX also questioned the immediate benefits to customers of the Clover Bar Distributed Control System (DCS) project, which is also related to EPGI's Y2K program.[65]

Position of EPGI

With respect to forecast boiler repair, steam drum level indicator and superheater clip replacement projects, Mr. Topping provided the following explanation and reasons, during cross-examination,[66] for the proposed repairs:

- The flame scanner installations are required under the Fire Protection Act.
- The steam drum level indicator replacements are required due to the age and unreliability of the existing indicators and that properly functioning indicators are required for safety reasons.
- The superheater clip replacement on unit 2 is required due to failures in the existing clips. Sound superheater clips are required for the operation of the unit.
- The buckstay corner upgrades are required due to the deterioration of the existing corners as a result of age and increased cycling of the plant to support increased requirements on the Alberta interconnected electric system.

[62] Tr. p.354f
[63] Tr. p.357
[64] Tr. p.360f
[65] Tr. p.363f
[66] Tr. p.355f

- The asbestos removal work is a continuation of EPGI's asbestos removal program which began in 1995 and which will be completed by the end of this year.
- General boiler repairs consist of work on units 3 and 4 that is being completed in conjunction with the outages for DCS and cold water outfall work.
- NOx abatement is being completed to improve control of NOx emissions at the plant.
- The acid tank is being replaced due to a recent failure for safety reasons.

It is EPGI's view that these projects are necessary to maintain unit reliability at current levels.[67]

The steam drum level indicator project was based on a failure rate assessment conducted in 1998 that showed a significant risk of failure. The timing of the project was based on delivery time for the item, as well as the timing of unit outages for the work to be completed.

The superheater clip replacement project was specific to unit 2.[68] The work was done on unit 1 in 1998. Mr. Topping testified that the need for the work only became apparent in the last four or five years with the increased cycling of the Clover Bar units. The clips are currently in "failure mode," meaning that EPGI has experienced clip failures that have led to either boiler leaks or forced outages of the unit.[69]

With respect to the increased capital costs associated with the cycling of EPGI's gas units, Mr. Topping explained that cycling has increased wear and tear on the units, which has resulted in higher capital expenditure requirements at Clover Bar.[70]

EPGI submitted that the evidence demonstrates that the forecast boiler repair, steam drum level indicator and superheater clip replacement projects are required and expenditures are being prudently incurred.

With respect to the transformer replacement project, Mr. Topping explained the need for the transformer is based on a condition assessment, which indicated that the paper insulation in the transformer had significantly deteriorated.[71] Mr. Topping explained that EPGI will replace a major component (such as the generator transformer) in situations where EPGI identifies a risk of imminent failure and there is significant lead-time for obtaining the component from manufacturers (e.g. 18 months in the case of the generator transformer). Such a replacement would occur in the first available outage to minimize unit downtime unless a failure occurred in the meantime, in which case the replacement would be made immediately. Mr. Topping stated that the purpose of EPGI's approach is to protect EPGI and its customers from the risk of an outage, and to minimize unit downtime in installing the necessary replacement. EPGI submitted

[67] Tr. p.358-359
[68] Tr. p.357
[69] Tr. p.362
[70] Tr. p.386f
[71] ENMAX-EPGI-35 (a)(i); Tr. p.360

that its equipment replacement policy is reasonable and appropriate, and that its forecast purchase of a replacement generator transformer is prudent.

With respect to the DCS, Mr. Topping pointed out the following:

- The immediate benefits to customers were described in detail in the project description filed in the 1996 GTA.
- Reliability improvements will be gained compared to the current boiler and turbine controls that have experienced failures.
- Increasing maintenance costs associated with increasing failure rates for the existing system over time will be avoided with the installation of the DCS, with the result that maintenance costs will be held flat.
- The DCS will provide a slight improvement by way of time saved in unit start-up. Increased production would total approximately 60 hours per year for the entire plant and, as Clover Bar would be on the margin in that range, the value of the improvement would be minimal.

Mr. Topping stated that it is clear that the DCS project will provide significant benefits to customers beyond those associated with Y2K issues. These benefits demonstrate that the forecast costs of the project are prudently incurred.

Board Findings

It appears to the Board that, while the FIRM Customers stated that they found it difficult to test the need for the maintenance and production improvement projects, the issue was really not about the need for the expenditures, but whether they will result in improved unit reliability. The FIRM Customers and ENMAX contended that, given the level of expenditures requested, unit availability should increase. On the other hand, EPGI's position was that the amount of expenditure requested will only maintain the current reliability level, not improve it.

Based on Mr. Topping's description of the nature of the work to be undertaken, the Board believes that, at a minimum, reliability will be maintained at recent or current levels. The Board, in the GENCO deferral account section, found that it was important to set the generating performance standard at a reasonable and demonstrably achievable level. The Board has directed in a previous section of the Decision that, for the purposes of EPGI's refiling, all forecast modeling parameters be determined using actual performance data over the three-year period 1996 - 1998. The Board is satisfied that, with the above method of determining generator performance standards, it would be appropriate to accept projects of this nature that are required to maintain recent generating performance. Therefore, the Board will allow the requested maintenance and production improvement capital additions into EPGI's rate base.

With respect to the transformer replacement, the Board notes that EPGI's condition assessment study indicated that replacement should be done by November/December 2000 at the earliest or

2003 at the latest. The Board considers EPGI's replacement policy, for a major component such as a transformer, to be a prudent and responsible one. The Board understands that transformers typically have long lead-times and can see the operational benefit to timing the replacement to coincide with the first available outage.

The Board recognizes that it can be costly if a transformer is replaced too much in advance of its window of need. The Board acknowledges ENMAX's argument that if one assumes that the time when a replacement would actually be needed is slightly beyond the start of the identified window of need, no capital expenditure would be required in the test years. However, the Board believes that any additional cost associated with replacing the transformer so that it is available at the start of the window of need is outweighed by the risk of not having the unit available to provide supply to the Power Pool. Therefore, the Board will allow the requested forecast expenditure.

The Board accepts EPGI's evidence with respect to the distributed control system expenditures and will allow these expenditures into EPGI's rate base.

(D) Genesee Black Start and Clover Bar Black Stop Projects

EPGI forecasted the addition of $3.7 million to its rate base in 2000 to install and commission a black start generator for the Genesee plant.[72] During the hearing, EPGI changed its project description, explaining this project would actually entail $1.5 million for black-stop capabilities for its Clover Bar unit[73] and $2.2 million for a black start generator for its Genesee units. Additional information regarding the black stop project is provided in Exhibit 37. The black-start generator is discussed in detail in ENMAX-EPGI-36 and FIRM-EPGI-29.

Position of the Intervenors

The FIRM Customers questioned the appearance of the Genesee black start and the Clover Bar black stop projects on the eve of the PPA world.

The FIRM Customers noted that EPGI admitted that its entire decision to install a black start generator for its Genesee units is based on the successful outcome of negotiations for selling black start services to the TA.[74] The FIRM Customers also noted that EAL recommended that the $2.2 million for the Genesee black start project should be removed from EPGI's rate base.

[72] Exhibit2, p.S-42
[73] Tr. p.448
[74] Tr. p.448

The FIRM Customers noted that EPGI did not do a risk assessment of future black start conditions on the Alberta interconnected system. They also noted, in the last twenty years, the Alberta system has yet to experience a single black start condition.[75]

The FIRM Customers submitted that the Board should exclude the Genesee black start project from EPGI's forecast of capital expenditures because it is speculative, at best, and does not contain an associated forecast of offsetting revenues from sales of black start capabilities to EAL.

The FIRM Customers noted that it was only during examination that EPGI explained it had an additional project in mind for the $3.7 million associated with the Genesee black start generators, namely the black stop diesel generation project at Clover Bar.[76] They stated that they were extremely concerned over EPGI's cavalier attitude towards explaining its capital requests. They believed that a Utility's application for general rate relief should form the full basis of its request. It should not simply be some type of "broad outline" or "general idea," nor should it effectively be a request for "blank check" treatment. Therefore, the FIRM Customers believed that the Board could, and should, reject capital funding for this project simply on the basis EPGI never adequately explained this project in its application.

The FIRM Customers questioned EPGI's sudden need to install black stop capabilities at Clover Bar. They noted that if Clover Bar were in dire need of black stop capabilities as EPGI currently claims, EPGI has had 25 years to add this capability to the plant. It could have installed it when building Clover Bar or at any time since. The only thing that has changed is the imminent arrival of the PPAs. The FIRM Customers asserted that this is EPGI's last chance to ask the Board for the money, hence the black stop project. In their view, this project is simply an attempt by EPGI to get something added to the plant it wants, but clearly does not need. Therefore, they proposed that EPGI's forecast of $1.5 million for black stop capabilities for Clover Bar should be excluded because that expenditure is not necessary.

The FIRM Customers stated that in the event the Board does endorse this expenditure (either for Genesee and/or any other plant), it must, in turn, reduce the forecast reservation payments for EPGI. Further, while EPGI recognizes black start services as an ancillary service generating payments from the TA, it does not include these offsetting revenues anywhere in its application.[77]

ENMAX noted that EPGI did not do a risk assessment as to the probability of requiring black start in the test years nor has it considered purchasing black start from the TA. ENMAX asserted that EPGI has simply identified a potential problem and, not willing to assume any risk has

[75] ENMAX.EPGI-36A (a)(ii)
[76] Tr. p.367
[77] Tr. p.369 and Tr. p.371

forecasted a need for the project. ENMAX noted that EAL considers the EPGI black start forecast to be premature.[78]

EAL confirmed that discussions have taken place between the TA and EPGI, but that no firm agreement has been reached. EAL noted EPGI's argument[79] that the TAOPs issued by the TA in early 1998 give rise to some uncertainty as to whether generating unit owners, or perhaps distributors, would be obligated to provide black start capability. EAL further noted that EPGI's statement contained no reference to specific operating policies in support of EPGI's claim. EAL pointed out that the TAOP dealing with black start is TAOP-1600.

EAL submitted that there is no uncertainty in the TAOPs. Black start is a system support service and must be arranged by the TA. In EAL's view the black start issue is a narrow one. EPGI has included the cost of a black start generator in its revenue requirement and the issue is whether, in the absence of an agreement with the TA, EPGI should be permitted to include that asset in its revenue requirement.

EAL submitted that the costs associated with black start capability are properly included in the revenue requirement of the TA, which will incorporate them in its transmission tariff. Capital expenditures by the owner of a generation unit, including EPGI, for black start capability should be approved by the TA and paid for through fixed payments under a contract between the TA and the service provider. EAL's position is summarized at page 3 of its opening statement[80] where it states:

> EPGI has included in their tariff a forecast capital amount of $2.2 million dollars to install Black Start capability at Genesee. Initial discussions on this matter have taken place but no firm agreement has been reached. It is the TA's responsibility to determine the need for and best method of procuring Black Start capability for the AIES. Accordingly, it is premature to assume that EPGI will be the provider of Black Start capability at Genesee. The forecast capital expenditure and associated costs should be removed from the EPGI forecast.

Position of EPGI

EPGI stated that the forecast expenditure related to the black-stop generator is prudent and, depending on the outcome of discussions with the TA, EPGI may be required to proceed with the purchase of a black-start generator as currently reflected in EPGI's Application.

EPGI's black-start project is described in ENMAX-EPGI-36 and FIRM-EPGI-29. There was some confusion during the hearing respecting EPGI's forecast expenditure of $3.7 million in 2000 for the black-stop and black-start generator projects.

[78] Exhibit 196
[79] Tr. p.371
[80] Exhibit 196

EPGI explained that the project labeled "Genesee Units 1/2 Black-Start Generator" in Schedule G-20-2000 is based on a supply interruption study initiated by EPGI, and is made up of two components. The first is a black-stop generator for EPGI's Clover Bar units that the study indicated was required.[81] Mr. Topping explained the need for the black-stop generator as follows:[82]

> It's a function of the safe rundown of the plant in the event of a provincial interruption of supply. So the plants have to safely run down from whatever load they were at to turning gear, and you keep the turbines on turning gear while the temperatures stabilize, and it's provision of that power that is inadequate at Clover Bar today.

Mr. Topping testified that whether or not EPGI will have to purchase a black-start generator will depend on the outcome of EPGI's negotiations with the TA respecting overall provincial black-start capability.[83] Mr. Topping stated that EPGI is of the view that black-start capability is an ancillary service. Therefore, it should be the responsibility of the TA. However, the operating policies issued by the TA in early 1998 indicated that black-start would be the responsibility of generating unit owners or perhaps distributors, giving rise to uncertainty as to which entity will be obligated to provide the capability.[84] Mr. Topping summarized the current status of discussions with the TA and of the project vis-à-vis EPGI's Application.[85] He indicated that the issue should be resolved with the TA by the end of this year.

EPGI submitted that there is a demonstrated need for black-stop capability at Clover Bar, and that the $1.5 million expenditure is clearly prudent and should be approved by the Board. EPGI further submitted that on a forecast basis the remaining $2.2 million for black-start capability is reasonable given the TA's operating policies.

Board Findings

The Board agrees with EAL that the black start issue is a narrow one. The EU Act places the responsibility for the provision of black start capability for the AIS with the TA, who decides how to procure such services in the most appropriate and cost-effective way.

The Board notes that although the TA has had discussions with EPGI, the TA has not made a decision with respect to obtaining black start capability services from Genesee. Notwithstanding any confusion that might have arisen from the interpretation of the TAOPs, the Board considers that it is premature for EPGI to include expenditures for black start capability at Genesee in its

[81] Tr. p.448
[82] Tr. p.368
[83] Tr. p.370; Tr. p.1464-1465
[84] Tr. p.371
[85] Tr. p.1575-1576

rate base. The Board concurs with EAL that capital expenditures by the owner of a generating unit for black start capability should be approved by the TA and paid for through fixed payments under a contract between the TA and the service provider. Accordingly, the Board will not allow EPGI's requested Genesee black start expenditures into its rate base.

With respect to the Clover Bar black stop project, the Board notes that questions have been raised about the need for this project, given that the plant has been in existence for a considerable length of time. The Board also notes that it was only during cross-examination regarding the forecast expenditure for the Genesee black start project that this project came to light. The Board considers that EPGI was remiss in not disclosing this project in its Application. Nevertheless, the Board considers that the undertaking by Mr. Topping to Ms. Quinton-Campbell[86] was helpful in understanding the nature and the need for the requested expenditure.

The Board considers that it is prudent to have an emergency generator to ensure the safe run down of the Clover Bar plant in the event of a provincial interruption of supply, even though such an event might be highly unlikely. The Board notes that similar and adequate black stop provisions exist at EPGI's other plants.[87] Therefore, for these reasons, the Board will allow into rate base the forecast black stop expenditures in respect of the Clover Bar plant.

For the reasons set out above, the Board directs EPGI, in its refiling, to reduce capital expenditures with respect to the Genesee black start project for the year 2000 by $2.2 million.

(E) Rossdale Decommissioning Costs

EPGI forecasts $12 million to be expended in 1999 for the final decommissioning and dismantling of the Rossdale low-pressure plant. Dr. Bridgeman indicated that about $800,000 of this amount would be used for asbestos removal.

Position of the Intervenors

The FIRM Customers stated that a significant amount of the capital additions relate to the decommissioning of Rossdale. They were concerned about the repowering of the Rossdale site under the unregulated arm of EPCOR and the appropriateness of the rapid write off of this expenditure. They noted that in discussing the upgrade to the Rossdale local area network, EPGI indicated it is applying for life extension PPAs to extend the plant life to as long as 2020.[88] Given this proposed life extension of the plant, the FIRM Customers questioned the need for adding $12 million to rate base in 1999 to decommission the plant.

[86] Exhibit 37, Tr. p.370
[87] Tr. p.366-367
[88] Tr. p.1092; l.12

IPPSA/SPPA noted that forecasts for demolition costs at Rossdale have been rising over the years and questioned the reasonableness of these costs, given that not enough information was provided to make that determination.[89] IPPSA/SPPA stated that it is very difficult to determine how much of the demolition cost is truly attributable to the regulated units. They asserted that EPGI has incentives to minimize costs associated with the construction of their non-regulated Rossdale 11 unit by moving costs to the decommissioning of their regulated units. IPPSA/SPPA submitted that the Board should reject any claims for increased decommissioning costs at Rossdale since the last study.

IPPSA/SPPA stated that a related question that begs asking is whether the repowering of Rossdale 8 is a sound capital investment. They noted that Rossdale 8 would be a waste heat recovery boiler that purchases steam from the non-regulated Rossdale 11 unit,[90] and that there was no information on the record to indicate that this is a beneficial arrangement for consumers. IPPSA/SPPA wondered whether the capital expenditure and fuel purchase associated with Rossdale 8 would be better for consumers than the retirement of the unit or a traditional gas-fired repowering. They asserted that one thing appears evident, that is, Rossdale 8 repowering makes Rossdale 11 a more economic venture for EPCOR. Under the guise of repowering a regulated generating unit, EPGI has created a steam user and turned what would otherwise be a single-cycle gas plant at Rossdale 11 into what is effectively a combined-cycle cogeneration plant. Moreover, EPCOR will be negotiating with itself to determine the price the steam from Rossdale 11 is sold to the regulated Rossdale 8 unit. IPPSA/SPPA questioned whether consumers would benefit in this arrangement. IPPSA/SPPA submitted that the Board should disallow any capital costs budgeted for Rossdale 8 until EPGI can demonstrate that the proposed Rossdale 8 repowering is of greater benefit to consumers than retirement or a more conventional life-extension.

Position of EPGI

EPGI noted that IPPSA/SPPA made the confusing argument[91] that whether or not the repowering of Rossdale Unit 8 is a "sound capital investment" is somehow relevant to this proceeding. It further noted that IPPSA/SPPA went so far as to assert that the Board should disallow any capital costs budgeted for Rossdale Unit 8 until EPGI can demonstrate that the proposed repowering is of greater benefit to consumers than retirement or a more conventional life extension.

EPGI stated that apart from being based on a misconception of the nature of the Rossdale Unit 8 repowering project, IPPSA/SPPA's argument about whether this proposal is a sound capital investment, has no relevance to the determinations the Board is required to make in this proceeding. EPGI submitted that the record is clear that there are no capital additions forecast for Rossdale Unit 8 in 1999 or 2000 which have any relation to the repowering or life extension

[89] Tr. p.5409-5411
[90] Tr. p.1350, l.11-23
[91] IPPSA/SPPA Argument, p.46-47

of Rossdale Unit 8.[92] Furthermore, the repowering will not occur until the year 2001, and issues relating to the costs of operating the repowered Unit 8 will be addressed under the PPA process that is currently ongoing.[93]

Board Findings

The Board will deal with the quantum of the proposed $12 million dollar decommissioning expense in a subsequent section of this Decision. The Board does not agree with EPGI that costs associated with the Rossdale low-pressure plant decommissioning should be capitalized and added to rate base. The Board considers that allowed decommissioning amounts should be charged to the accumulated depreciation reserve. Accordingly, the Board directs EPGI, in its refiling, to remove $12 million from 1999 capital expenditures.

(F) Projects of less than $1.0 million

Projects of less than $1 million totaled $5.9 million in 1999 and $11.2 million in 2000. A brief description of these projects was given in ENMAX-EPGI-33 (b).

Position of the Intervenors

ENMAX noted that EPGI have over $17 million in projects, which individually have a capital cost of under $500,000. ENMAX.EPGI.33 (b) lists those projects with a brief description of each. The total of these forecast projects exceeds all of the capital additions in 1996. ENMAX submitted that if one were looking to save money by not doing some capital items this would provide a painless place to do so.

Position of EPGI

EPGI noted that ENMAX made the assertion that, "If one were looking to save money by not doing some capital items this [i.e. projects of less than $1.0 million] will provide a painless place to do so."[94] EPGI submitted that it appears that ENMAX must be of the view that because the projects listed in ENMAX-EPGI-33 (b) are of a value less than $1.0 million, they must somehow be less necessary than more expensive projects or are unnecessary altogether.

EPGI stated that ENMAX's assertions have no factual basis and ignore the relevant evidence, which EPGI provided. EPGI noted that Intervenors chose not to pursue these projects in any significant detail in cross-examination and did not provide any evidence that refutes the prudence of these costs. EPGI submitted that its evidence demonstrates that the projects are required and that the costs are prudently incurred.

---

[92] IPCAA-EPGI-19
[93] Tr. p.1353
[94] ENMAX Argument, p.79

Board Findings

The Board agrees with EPGI that just because a project has a value of less than $1.0 million does not mean that it is less necessary or not necessary. The Board notes that ENMAX neither provided any information as to which of the projects can be eliminated, nor did it suggest the basis on which the Board might disallow a project. The Board agrees with ENMAX that because of the number of smaller projects there is more opportunity to defer or cancel some of the projects.

The Board considers that it would be appropriate to recognize EPGI's past history of over forecasting by reducing this category by 10% for each of 1999 and 2000. The Board recognizes that this figure is subjective and is based on a fair amount of judgement. However, the Board believes that 10% is more appropriate than EPGI's imputed past average over-forecasting record of approximately 20% (see Board Findings in section (A) above) or the 25% negative contingency proposed by ENMAX. This belief is based on:

- The Board's expectation that EPGI's forecasting procedures are continually improving.
- The average 20% over-forecasting error is comprised of errors relating to forecast expenditures for small and large projects. Because of their significance vis-à-vis the smaller projects, the Board believes that average expenditure forecasting errors associated with larger projects would tend to be greater than the total overall average of 20%. Consequently, average expenditure forecasting errors associated with smaller projects would tend to be lower than 20%.

Accordingly, the Board directs EPGI, in its refiling, to remove $0.6 million from 1999 and $1.1 million from 2000 the capital expenditure category entitled "projects less than $1.0 million."

(G) 1992 Clover Bar IP Rotor Replacement and 1993 Insurance Claim

In 1992, EPGI (then Edmonton Power Inc., will be referred to as EPGI for the purposes of this discussion) decided to repair and replace two intermediate pressure rotors in Clover Bar Units 1 and 2. This involved approximately $4.1 million in capital expenditures that were included by EPGI in their 1993 EEMA adjustment filing.[95]

In 1993, EPGI made a $1 million claim against the reserve for self-insurance as shown in its 1994 forecast filing and provided details of the claim in CR.EP-13 of the 1994 EEMA Forecast proceeding. In that proceeding Mr. Topping said the insurance company had rejected EPGI's claim and indicated that the claim was in litigation.[96]

[95] Tr. p.804
[96] Sept. 20, 1994, Tr. p.255-256

The Court of Queen's Bench heard the case and rendered a decision that dismissed EPGI's claim. That decision was appealed to the Alberta Court of Appeal, which in a very brief judgement unanimously agreed with the trial judge and dismissed the appeal.[97] EPGI has now applied for leave to appeal to the Supreme Court of Canada. Dr. Lewin and Mr. Topping indicated that the lower courts' determination that EPGI missed a one-year time limitation period within which to initiate legal proceedings is the subject of the leave application to the Supreme Court of Canada.[98]

Position of the Intervenors

The FIRM Customers asserted that EPGI:

- was imprudent for failing to initiate a claim against its insurer within a limitation period;
- should have initiated an action against the lawyer who acted on its behalf and who failed to file a statement of claim in respect of the rotor replacements within the limitation period;
- should have initiated an action against the manufacturer of the rotor or alternatively against a successor to the manufacturer; and
- should have initiated an action against the manufacturer's insurer.

On the basis of the foregoing, the FIRM Customers proposed that EPGI's revenue requirement be reduced.

The FIRM Customers contended that EPGI failed to file suit against its insurers in a timely fashion. Consequently, EPGI lost an otherwise meritorious legal claim to cover this cost through insurance. The FIRM Customers relied on the decision of the Court of Queen's Bench and the decision of the Alberta Court of Appeal respecting EPGI's insurance claim against its insurer. In the trial judgement, the court held that the effect of statutory condition 14 of the policy, a one-year limitation period within which to commence a legal action, in the circumstances before the court, was to effectively bar any action by EPGI against its insurer. The FIRM Customers questioned the likelihood of success of EPGI's application before the Supreme Court of Canada. They noted that there was no dissenting opinion from the Alberta Court of Appeal, the issue was not one of "public or national importance", and that there are no conflicting decisions on this issue among or between Canadian jurisdictions requiring our highest Court to resolve. The FIRM Customers submitted that the leave to appeal application served only to delay this matter.

The FIRM Customers submitted that EPGI, in responding to MI.EPGI-16(c), chose not to disclose that the trial judge found that EPGI missed the one-year limitation period. They asserted that the trial judge in a lengthy decision found there was coverage under the insurance policy for

[97] Exhibit 40
[98] Tr. p.810

the damage to the two rotors. However, he dismissed the claim because EPGI and their lawyers neglected to file a statement of claim within the one-year limitation period.

The FIRM Customers noted the trial judge held that a deductible of $1 million per each rotor would have applied to the claim of $4.25 million. Had he awarded any damages to EPGI, this would have reduced EPGI's net award to $2.25 million plus prejudgment interest from the date of loss plus costs.[99] Under the *Judgment Interest Act*, using 23 April 1992 as the date of loss, prejudgment interest would be $794,789.39, as at 21 June 1999, and $215.75 per diem thereafter. The FIRM Customers submitted that, while court costs are not known, a conservative estimate would be $225,000. Therefore, had EPGI been awarded damages, it would have received $3,269,789.

The FIRM Customers also contended that EPGI made no attempt to pursue the lawyer who missed the limitation period. They noted that EPGI did not provide an adequate explanation for not doing so. The FIRM Customers surmised that EPGI did not pursue such action because the lawyer involved was employed with the City of Edmonton Legal Department.[100] They suggested that had outside counsel been used, the law firm would surely have been sued and held liable.

Additionally, the FIRM Customers argued that EPGI acted imprudently in not pursuing a claim against the manufacturer, the manufacturer's successor or the manufacturer's insurer. They asserted that, since no deductible is applicable, a successful lawsuit would have resulted in recovery of the entire loss, plus prejudgment interest and costs. This amounts to approximately $5.7 million and is the sum of the claim of $4.25 million, plus prejudgment interest thereon from 23 April 1992 in the sum of $1,501,268.84 to 21 June 1999.

The FIRM Customers submitted that given the evidence now before the Board regarding EPGI's imprudent actions it is not fair or reasonable for EPGI to benefit from its own mistakes at the expense of its customers. They proposed that a reduction to EPGI's revenue requirement should now be made. This, they believe, would avoid the Board having to deal with this issue at a later date. The FIRM Customers submitted that, if in the unlikely event EPGI should succeed in obtaining leave and win the appeal, then EPGI could keep the fruits of its litigation.

In conclusion, the FIRM Customers submitted that, to hold ratepayers harmless from the result of EPGI's imprudence, the Board should remove $5.7 million from EPGI's revenue requirement. In the event that the Board finds that EPGI acted prudently with respect to its lawyer, the original rotor manufacturer, its successor or the manufacturer's insurer, then EPGI's rate base should be reduced by $3,269,789. This being the cost of imprudence of not making a claim against EPGI's insurance company within the one-year time limitation period.

[99] Trial Decision, paragraph 356
[100] Tr. p.1423

Position of EPGI

EPGI submitted that the FIRM Customers unfairly characterized EPGI's efforts in pursuing compensation from its insurer for the IP rotor as being imprudent. It stated that the Corporation has in all respects taken reasonable care in pursuing recovery for the benefit of its customers. EPGI retained appropriate legal counsel and other experts to act on its behalf and has tenaciously pursued a very difficult and complex claim against its insurer for over six years. EPGI argued that it would be entirely unfair to penalize the Corporation for failing to be successful in achieving recovery from its insurer when the facts demonstrate that the Corporation has taken all reasonable steps to protect the interests of its customers.

EPGI stated that the complexity of the limitation issue is illustrated by the erroneous assertion in the FIRM Customers' argument that had a statement of claim been issued by the end of March, 1993, EPGI would have won the lawsuit. EPGI submitted that this conclusion by the FIRM Customers is simply wrong, as the trial judge makes no such determination. EPGI argued there is no evidence on the record supporting the FIRM Customers' allegation that EPGI would have won the lawsuit if a claim had been made by the end of March 1993.

EPGI noted that the FIRM Customers criticize EPGI for not pursuing an action against the City of Edmonton's lawyer who initially acted for the corporation at the time the claim was filed against the insurer and who, arguably, failed to file the claim within the applicable limitation period. However, they provided no evidence that bringing an action against the lawyer would have provided any benefit to customers. EPGI stated City lawyers do not carry liability insurance and, consequently, bringing a negligence action against a City lawyer, even if successful, would not have resulted in any meaningful recovery. EPGI submitted that the cost of pursuing such a claim would likely be greater than the monies recovered. EPGI concluded that overall it would have been imprudent for EPGI to initiate a claim against its legal counsel, and there is no logical basis for the FIRM Customers' assertions in this regard.

EPGI rejects the contention that it could have recovered the replacement cost of the IP rotors had it simply pursued either the original manufacturer, its successor or insurer, pointing out that there is no evidence for this assertion.

EPGI argued that the FIRM Customers are simply wrong both in fact and in law. They chose to ignore the fact that the rotors were over 20 years old at the time of their failure, or alternatively must be unaware of the effect that their age would have on the recovery that would occur as a result of a successful action against the manufacturer. EPGI stated that at law, a claim against the manufacturer could only result in a recovery equal to the original cost of the rotors, less accumulated depreciation, at the time they were taken out of service. EPGI submitted that given the rotors were in service for 20 years, and given that each of them was only one component of the turbine unit, their depreciated value would have been nominal. EPGI argued that it would be highly doubtful that the depreciated value of the rotors would even equal the cost of pursuing the claim against the manufacturer or any successor to the manufacturer, whether foreign or

Canadian, would have been uneconomic. Therefore, it would have been imprudent for the Corporation to pursue such a claim.

EPGI also noted that the FIRM Customers alleged that EPGI could have recovered the replacement cost of the rotors had it simply pursued recovery from the manufacturer's insurer. However, they provided no evidence for this assertion. EPGI stated that the FIRM Customers are either unaware of or choose to ignore the fact that general liability policies issued to manufacturers normally contain a work product exclusion. The effect of this provision is to exclude coverage for claims arising from certain events. These events are (i) injury, destruction or loss of use of goods or products manufactured or sold by the insured (i.e. manufacturer) and (ii) work done by or on behalf of the insured where the loss arises from a defect in the work product. EPGI stated that failure to include this exclusion in a manufacturer's policy would have the effect of making the insurance policy a "warranty" for the product manufactured. Hence, the reason for their inclusion in general liability policies. Accordingly, EPGI submitted that it is highly unlikely that any claim would have been possible against the manufacturer's insurer, even if such an insurer could have been identified. Therefore, it would have been imprudent for the Corporation to pursue such a claim.

Dr. Lewin testified that the "claim was being pursued on the understanding any money recovered would be applied against the appropriate capital account ... essentially for the customers' benefit."[101] Also, in response to an undertaking,[102] Dr. Bridgeman indicated that if EPGI obtains a judgement that results in recovery of money in connection with the Clover Bar insurance claim after 2000, EPGI proposes to pay that sum, net of any reasonably costs incurred in pursuing the claim, to the Balancing Pool.

In summary, EPGI requested that the Board reject the arguments proffered by the FIRM Customers.

Board Findings

In its Decision regarding the 1993 EEMA adjustment filing by EPGI, the Board allowed the cost relating to the replacement of the Clover Bar intermediate pressure rotors to be included in EPGI's rate base. The Board understands that EPGI subsequently commenced an insurance claim to recover the cost of replacing the rotors. The claim was rejected by the insurance company and then became the subject of litigation.

The Board further understands that the Alberta Court of Queen's Bench and the Alberta Court of Appeal determined that EPGI had not complied with an applicable time limitation period to commence legal proceedings against its insurer. The Board notes that the trial court judge found that the effect of the policy's statutory condition 14 (the one-year limitation period) was to effectively bar any action by EPGI against its insurer, given the circumstances before the court.

[101] Tr. p.803
[102] Tr. p.1503

2. EPGI
(a) Rate Base

EPGI currently has a leave application before the Supreme Court of Canada in respect of the decisions of the lower courts.

The Board acknowledges that the courts will ultimately resolve the private contractual rights and obligations between EPGI and its insurer. However, it is the view of the Board that this matter can be finally resolved from a regulatory perspective in this proceeding. The Board considers that the issues to be addressed are twofold. First, the Board must determine whether, for regulatory purposes, the actions of EPGI in attempting to recover the cost of the Clover Bar IP rotors were prudent and reasonable. Next, depending on the determination of the first issue, the Board must decide how it should treat the cost of replacing the rotors, which are currently in rate base.

On the evidence before it, the Board is unable to determine whether legal action against EPGI's lawyer or the rotor manufacturer, its successor or their insurers would have constituted a reasonable and prudent approach. It is the Board's view that this is not the case with respect to the actions taken by EPGI to recover the rotor costs against its own insurer. Therefore, the Board will confine its assessment and remarks to EPGI's pursuit of a claim against its insurance company.

The Board considers the management of EPGI to be astute and capable, with direct access to top quality commercial and legal expertise in the various areas of its operations, including insurance matters. The Board is of the view that EPGI should have been alive to the issue of time limitation periods in its insurance contracts generally, and more particularly aware of statutory condition 14 which purported to impose a one year limitation on claims. Given the potential consequences of failing to comply with the time period, the amount of the claim, EPGI's business acumen and the relative ease with which such legal proceedings could have been filed, the Board believes that it was incumbent on EPGI to act in a manner which would have preserved EPGI's rights and foreclosed the likelihood of a future dispute with its insurer regarding the timing of the claim. EPGI did not act in this conservative and careful manner.

Accordingly, the Board believes that it would be fair and reasonable for EPGI to bear the costs of the amount of the insurance claim that potentially could have been recovered had EPGI pursued the claim in a timely manner. The Board considers that the potentially recoverable amount, with interest, would be approximately $3.0 million as computed by the FIRM Customers. The estimated legal costs of $225,000 may also have been recoverable, however, the Board considers that they were prudently incurred and should be borne by the customers since customers would have wanted EPGI to pursue an insurance claim to recover the cost of replacing the rotors. The Board considers that it would be fair and reasonable for EPGI's shareholders to benefit from any amounts recoverable resulting from a favorable ruling from the Supreme Court even if such amounts exceed $3.0 million.

2. EPGI
(a) Rate Base

The Board directs EPGI, in its refiling, to reduce the Clover Bar plant balance by $3.0 million effective 1 January 1999. Further the Board directs that any future recovery resulting from a favourable ruling will be to the benefit of the shareholders account.

(H) Summary of Capital Additions

Summary of Views

Issue or Concern	1999			2000		
	EPGI	Intervenors	Board Findings	EPGI	Intervenors	Board Findings
Historical vs. Forecast Capital Expenditures Levels		No greater than $20M (FIRM) 25 % negative contingency (ENMAX)	Have regard for trends, but assess each major capital addition for need and prudence.		No greater than $30M (FIRM) 25 % negative contingency (ENMAX)	Have regard for trends, but assess each major capital addition for need and prudence.
Mine Related Capital Expenditures	$6.2M	No more than $3.0M (FIRM)	No reduction.	$4.1M	No more than $3.0M (FIRM)	No reduction.
Clover Bar Capital Expenditures	$10.7M	Expenditures should improve performance Compare to 1996 additions (ENMAX)	No reduction.	$10.9M	Expenditures should improve performance	No reduction.
Genesee Black Start Clover Bar Black Stop				$2.2M $1.5M	-$2.2M (EAL) -$3.7M (FIRM)	-$2.2M
Rossdale Decommissioning Costs	$12M	Disallow all costs since last study. (IPPSA/SPPA)	-$12M[103]			
Projects of less than $1.0 million	$5.9M		10% reduction -$0.6 M	$11.2M		10% reduction -$1.1 M
Capital Additions, including items above	**$38.5M**		**$25.9M**	**$52.7M**		**$49.4M**
1992 Clover Bar IP Rotor Replacement and 1993 Insurance Claim	$4.1M in 1993	-$5.7M or $3.3M at min (FIRM)	$3.0 million reduction.[104]			

[103] Removed from capital additions. Will be dealt with in the Rossdale decommissioning section.
[104] To be removed from Clover Bar plant balance effective 1 January 1999.

(2) Necessary Working Capital

The inclusion of necessary working capital (NWC) in rate base recognizes the average investment required by a utility to bridge the lag between when the service was rendered and the related expenses were incurred and when the revenues were received to recover such expenses. NWC also includes amounts reflecting the investment in inventories of materials, supplies and other assets necessary to the operation and maintenance of the utility system.

EPGI filed working capital calculations by updating the various lead/lag schedules for current payment and receipt patterns. EPGI indicated that many of the changes were minor in nature but were accounted for in the lead/lag schedules. The following table summarizes EPGI's working capital requirements for 1999 and 2000.

	1999		2000	
Working Capital Requirements	**Lead/Lag Days**	**Working Capital ($million)**	**Lead/Lag Days**	**Working Capital ($ million)**
Operating expenses	17.5	11.1	17.3	9.8
Inventory		8.2		8.5
Mid-year Debt Interest	(70.4)	(13.7)	(71.1)	(12.9)
Mid-year Equity				
Common return	43.8	4.1	44.0	4.2
Dividend return	30.1	2.8	28.8	2.7
Mid-year Depreciation	45.3	4.0	45.3	4.6
Unamortized Deferred Costs	0.0	0.4	0.0	0.7
Total Working Capital		16.9		17.6

Intervenors expressed concern as to the (A) reduction of lead/lag days for other operating expense, (B) calculation for the net lag on the dividend payment and (C) valuation of inventory at 31 December 2000.

(A) Operating Expenses

Position of the FIRM Customers

The FIRM Customers indicated that EPGI reduced the number of days in the payment lag by 21.0 days from 42.6 days in the 1996 GTA to 21.6 days in the Application. Although there was a reduction of 21.0 days in the payment lag, the FIRM Customers submitted that EPGI had not indicated any change in the policy concerning the length of time for payment of vendor invoices.

The FIRM Customers stated that EPGI indicated the proposed lag reflected the time from the vendor's invoice issue date to EPGI's payment date.[105] However, the FIRM Customers suggested this time span was contradicted by EPGI's evidence how the 21.6 days was calculated from the October 1998 aged accounts payable where only booked invoices appeared. The FIRM Customers suggested it was unclear whether any adjustment was made for the time lag from the invoice issue date to invoice booking date. The FIRM Customers suggested that the lag time between the consumption of goods and services and the invoice date was also not reflected in the 21.6 days. Although EPGI indicated certain prepayments would offset this lag, the FIRM Customers restated the uncertainty of whether or not the lag from invoice date to booking was reflected in the 21.6 days.

The FIRM Customers suggested that, in terms of explaining the decrease in the lag time, EPGI attributed computerized processing and electronic payments to suppliers as the primary reasons. The FIRM Customers reiterated that the 21.6 days, proposed by EPGI, still appeared low. The FIRM Customers suggested that if the consumption to invoice period was taken into consideration, even a 30-day payment policy from invoice date would have resulted in a lag greater than 30 days.

The FIRM Customers recommended that, given EPGI had not changed its policy on payment of vendor invoices, the 42.6 days, accepted in 1996, should be applied in 1999 and 2000. The FIRM Customers asserted that 42.6 days should be used, particularly in the absence of a comprehensive analysis by EPGI updating the lags associated with other expenses. The FIRM Customers stated that correcting this lag would result in a reduction in EPGI's working capital of approximately $2.6 million in 1999 and $2.4 million in 2000.

Position of EPGI

EPGI stated that the FIRM Customers' claim that a 21.6 day lag was low was without merit. EPGI claimed that it had not stated nor presented any evidence suggesting that its policy was to pay within a 30-day period. EPGI noted that the policy respecting the payment of vendor invoices, to pay no later than due, had not changed. EPGI stated it was taking advantage of discounts and claimed this practice, along with the use of electronic payments, provided evidence to substantiate the forecast of a 21.6 day lag in payments.

Contrary to the FIRM Customers' assertion, EPGI stated there was no contradiction in its evidence. EPGI explained that, although the October, 1998 aged accounts payable report only included booked invoices, the accounts payable report showed the date on which the invoice was issued and not the date on which the invoice was received. EPGI asserted that the lag from consumption of goods and services to invoice date was reflected in the 21.6 day lag. EPGI postulated that the lag from consumption would be offset by prepayments, thus making it unnecessary to add significant work and complexity to the lead/lag study by including this factor.

[105] Tr. p.1041, l.13

Board Findings

The Board has considered, in previous Decisions, that the calculated expense lag should commence at the time the goods or services are rendered to the utility. In the study, EPGI indicated that the calculations to determine the 21.6 day lag began at the time of the invoice issue date. EPGI assumed the time lapsed between the instance of EPGI's consumption of the goods or services and the suppliers' issue date of the invoice is offset, generally, through prepayments made by EPGI. Mr. Vaasjo provided further explanation as follows:

> Q Did you consider the lag from the time services rendered or the goods are received to the receipt of the invoice and then to the booking of the invoice?
>
> A MR. VAASJO: That was considered. The difficulty surrounding that is it is a massive amount of work to undertake to analyze that account. In addition to that, there are charges that are -- or payments that are in advance, for example, rent, auditors' fees, to name a couple, that are payments in advance. So there is, to some degree, some offset in that determination. It is not all just one way in terms of payments happening after services provided. There are also payments in advance of service being provided. So we didn't feel that given that there was some degree of offset and, in respect of lead/lag studies, that particular line is the one that typically makes lead/lag studies huge studies, we concluded that we would just utilize the 21.6 days, which is as noted in Note 1.[106]

The Board notes that EPGI's policy on payment of vendor invoices, which is to pay no later than the due date, has not changed. However, in today's electronic age, payments can be managed to take advantage of vendor offered discounts and avoid late payment charges.

The Board notes that EPGI did not provide any specific evidence to support EPGI's claim that the time lapsed between the rendering of service and the suppliers' issue date of the invoice is completely offset through prepayments made by EPGI. The Board considers this to be a critical assumption that has a significant effect on the expense lag calculation. The Board considers that the proportion of expenses prepaid would be less than the other operating expenses not prepaid. The Board, in the absence of such evidence, will assume that the time between rendering of service and the issue date of the suppliers invoice would be approximately 15 days on a weighted average basis, considering both prepaid and non-prepaid expenses. Accordingly, the Board considers that the expense lag should be increased to 36.6 days for other operating expenses. The Board notes that its finding of 36.6 days lag recognizes a six day improvement from the expense lag approved in the 1996 GTA. The Board considers this to be reasonable given the ability to manage payments through electronic processing.

[106] Tr. p.1039-1040

For all of the above reasons, the Board directs EPGI, in its refiling, to use a 36.6 day expense lag for other operating expenses in the calculation of necessary working capital for 1999 and 2000.

(B) Dividend Payment

Position of the FIRM Customers

The FIRM Customers stated that there should be consistency between dividend payment frequency and rate of return. The FIRM Customers submitted the rate of return evidence before the Board reflected the returns of more widely held corporations with quarterly dividend payment patterns. Accordingly, the FIRM Customers submitted either EPGI's rate of return should be adjusted downward to reflect monthly dividend payments or the working capital reduced to reflect quarterly payments. For purposes of this proceeding, the FIRM Customers recommended reducing EPGI's working capital by reflecting a quarterly dividend payment. The FIRM Customers suggested that reflecting a quarterly dividend payment would reduce the dividend payment lag about 30.4 days and, in turn, would lower the working capital by about $2.8 million in both 1999 and 2000.

Position of LE/RD

LE/RD submitted that the EPGI working capital calculations should be revised to reflect payment of dividends on a quarterly basis, consistent with usual corporate practice. LE/RD noted that EPGI calculated the effect on working capital, by assuming payment of dividends on a quarterly basis, would be a reduction to working capital of $3.0 million for 1999 and $3.7 million for 2000. LE/RD submitted that EPGI should be directed to make that change.

Position of EPGI

EPGI stated there was no foundation in the record for the FIRM Customers' claim that "the rate of return evidence before the Board reflected the returns of more widely held corporations with quarterly dividend payment patterns." EPGI stated there was nothing to suggest that the "usual pattern" of dividend payments for widely held corporations should be applied in the determination of EPGI's working capital. EPGI noted that it was required to make monthly dividend payments, pursuant to a long-standing obligation to do so, to its sole shareholder, the City of Edmonton. EPGI submitted that actual obligations respecting dividend payments should be used in the calculation of the working capital requirements.

EPGI also asserted no evidence was presented to support the FIRM Customers' claim that there was a connection between market rates of return on equity and the timing of dividend payments. EPGI rejected the FIRM Customers' suggestion that a downward adjustment to the rate of return should be made to reflect EPGI's monthly dividend payment cycle.

EPGI stated that, in an attempt to substantiate their position, LE/RD had taken EPGI's evidence out of context when LE/RD suggested that EPGI's working capital calculations should be

revised to reflect payment of dividends on a quarterly basis, consistent with usual corporate practice. EPGI contended that the payment of dividends on a quarterly basis was the more "usual pattern" for more widely held corporations, whereas it was probably not unusual for wholly-owned corporations, such as EPGI and EPCOR, to pay dividends on a monthly basis.

Board Findings

The Board considers that there is an obvious and direct connection between the frequency of dividend payments and the effective rate of return that can be earned by shareholders through compounding as a result of the time value of money. The Board notes that EPGI has an obligation to make monthly dividend payments to its shareholder which, according to the evidence, is discharged. However, the Board considers that the resulting additional NWC expense charged to customers by using monthly dividend payments in the lead/lag study, directly translates into the opportunity to achieve a rate of return that exceeds the allowed rate of return for EPGI's shareholders. The Board does not consider this to be equitable since EPGI's allowed rate of return is made comparable to widely held corporations of similar risk where the standard practice is to make quarterly dividend payments.

The Board agrees with the Intervenors that the most effective way of rectifying the above inequity, is to deem a quarterly dividend payment for the purposes of calculating EPGI's NWC. The Board considers that this will lower the fair return and monthly dividends appropriately, such that the compounding of the lower monthly dividend payments will be consistent with the comparable allowed rate of return.

Accordingly, the Board directs EPGI, in its refiling, to deem a quarterly payment of dividends in the calculation of necessary working capital for 1999 and 2000.

(C) Inventory Valuation at 31 December 2000

Board Findings

The Board has provided its findings on inventory valuation in Part 1–General of this Decision. For purposes of this Decision, the Board accepts EPGI's mid year inventory valuation for working capital of $8.2 million and $8.5 million for 1999 and 2000 respectively.

(D) Remaining Items

Board Findings

The Board has reviewed and accepts the lead/lag calculations for all remaining items in the calculation of necessary working capital for 1999 and 2000. Therefore, the Board directs EPGI, in its refiling, to use the lead/lag days as calculated for the remaining components of necessary working capital for 1999 and 2000.

The Board notes that EPGI has been directed to make changes to the costs in each expense category. The Board directs EPGI, in its refiling, to revise the 1999 and 2000 necessary working capital using the Board approved costs in each expense category.

(b) Minimum Return Margin

EPGI proposed to introduce a minimum return margin (MRM) for Rossdale and Clover Bar generating stations. EPGI expressed concerned that the net original cost rate base-determined earnings requirement for Clover Bar and Rossdale were insufficient to fairly compensate for the operating leverage risks associated with the continued operation of these facilities. The minimum return margin was based on certain operating expenses and designed to compensate for the increased operating leverage risks associated with Clover Bar and Rossdale.

The MRM was a calculated mark-up on cash. This method established some protection against default on cash obligations which became the primary business risk once the net original cost rate base diminished and capital recovery risk was no longer a primary concern.

Position of the FIRM Customers

EPGI submitted a protracted argument on an issue the FIRM Customers, other customer groups and, apparently, the other two generating Utilities consider to be a post-2000 or PPA issue. Not unlike the decommissioning reserve, this appears to be an attempt to advance certain PPA concepts in an effort to increase EPGI's return in 1999 and 2000. The FIRM Customers took exception to a number of EPGI's arguments.

First, EPGI asserted "...the determination of revenue requirements, risks and prospective rates of return for 1999/2000 must necessarily take place on a station-by-station basis."[107] It appears this position is based on EPGI's unique perception or reading of the EU Act as neither of the other two generators singled out their older, and higher depreciated units, for such treatment in their filings. Although AE is currently requesting a minimum return for its units, the request is in the context of its PPAs. As noted in the FIRM Customers argument, Mr. Marcus takes the position

> ...it is highly premature to unbundle EPGI into three generating stations. While this issue might need to be considered as part of the IAT process and the development of power purchase contracts, EPGI is not unbundled yet...[108]

Position of ENMAX

ENMAX would not object to the use of the minimum return concept if EPGI were prepared to accept a lower return on the other generating units so that the overall average rate of return for EPGI was maintained at the level recommended by Dr. Waters and Dr. Winter. Absent such an

[107] EPGI Argument, section 8.1
[108] FIRM Customers Argument, p.55

adjustment by EPGI, ENMAX can only conclude that the proposal by EPGI is merely an attempt to enhance its return.

Position of LE/RD

LE/RD noted that this is not an overall utility risk, but only a risk with respect to a particular unit or units (that is, based on the traditional rate base return recovery, there is not a predictable risk that the utility on a global basis will have insufficient revenues to cover operating expenses). EPGI stated that the movement to the PPAs required the utility to come up with an arrangement on a unit basis which appropriately protected the utility with respect to the risks of operating the unit. That was the genesis of the minimum return margin recommendation. However, for the test years 1999-2000 recovery of costs is not on an unit basis (although costs are calculated on an unit basis, the tariff is established on a global basis for recovery from distribution systems), and therefore LE/RD agree with Mr. Marcus that the proposal to recover a portion of return based on a minimum return margin is premature. Furthermore LE/RD submitted that none of the supporting material provided by Dr. Evans in his response to BR-EPGI.18, or his rebuttal evidence, Exhibit 39 at p.23, appeared to refer to a single unit based application of the minimum return margin calculation where a global utility assessment would not justify such margin.

LE/RD therefore submitted that the Board should reject use of the minimum return margin for the purpose of calculating the necessary return on equity for EPGI for the test years 1999-2000.

Position of IPPSA/SPPA

In its argument, ENMAX noted many flaws with the minimum return margin concept and IPPSA/SPPA supported the position that the minimum return margin concept should not be adopted by the Board. Just because the IAT determination was anticipated to require a PPA auction on a station by station basis after the year 2000 provided no rationale for adopting a minimum return on a station by station basis in the test period. The IAT will determine the appropriate rate of compensation for each unit post-2000. IPPSA/SPPA submitted the Board is making a rate of return calculation for EPGI, as a corporate whole, now. As a corporate whole, EPGI has no need for minimum return margins.

Without a minimum return margin, EPGI stated it has an incentive to close and decommission the Clover Bar and Rossdale plants. EPGI concluded that market power would increase because the number of generators would be reduced. IPPSA/SPPA disagreed with EPGI's position. If EPGI is unhappy with the rate of return on these units, it has the option of selling them to new entrants rather than decommissioning. Pursuit of this option may, in fact, decrease market power through new entrants and reduce costs to consumers through avoided minimum return margins and decommissioning costs – thereby furthering the goals of deregulation.

Position of EPGI

EPGI submitted that common equity investors in 1999/2000 evaluate the long-term risks of EPGI in arriving at their decisions respecting required rates of return and the long-term risks include risks that will be operative during the PPA period. The IAT has determined that PPAs will be sold on a station-by-station basis for EPGI. Thus, the determination of revenue requirements, risks and prospective rates of return for 1999/2000 must necessarily take place on a station-by-station basis. Even within the 1999/2000 test period, the Board must fix appropriate reservation prices and therefore develop revenue requirements on a station-by-station basis.

Dr. Bridgeman stated:

> The Act, my reading of it, requires the Board to establish an aggregate reservation price and (sic) UOPs. It also requires the establishment of unit reservation prices, and it is our belief that those prices ought to be representative of the costs and the risks associated with each of the units, and to do some sort of averaging, implying some sort of cross subsidization between the units, we do not believe is appropriate. The prices established by the Board should, in our assessment, fairly reflect the business activities and costs associated with those units, and we think that EPGI is the entity before you, but there is a need to establish prices for those units, and we think they should be set appropriately based on the risks, the costs of those units.[109]

Dr. Evans, on behalf of EPGI, submitted that the combined effect of treating generating stations on a separated basis for regulatory purposes and the sale of power contracts at the station or unit level as contemplated in the PPA world require that the Board now address the unusual "vanishing rate base" problem. For practical purposes, Rossdale's net original cost rate base is zero in 1999/2000. Clover Bar's net original cost rate base is $60-70 million.

The application of virtually any rate of return to the net original cost rate base of Rossdale and perhaps Clover Bar will produce return requirements which fail to compensate for the operating leverage risks to which these facilities are exposed. This is because the operating component of the revenue requirement becomes more significant as the rate base declines and variations in operating expense can not be absorbed by the return component of the revenue requirement. Moreover, the earnings requirements determined by the rate of return on rate base method provide no incentive for EPGI to devote scarce management and operating personnel to the continued operation of these facilities.

In order to properly recognize the operating leverage risks of Rossdale and Clover Bar, Dr. Evans recommended that the Board adopt a minimum return margin in conjunction with its traditional rate of return method for determining earnings requirements. Dr. Evans defined the minimum return margin to be the ratio of cash income (net income plus depreciation) divided by

[109] Tr. p.601, 602

total revenues less depreciation less fuel. Based on a study of cash default margins for Clover Bar and Rossdale, Dr. Evans concluded that the minimum return margins for Clover Bar and Rossdale should be 15.75% and 26.25% respectively. Dr. Evans recommended that the traditional return method be supplemented with the minimum return margin to address the problem of operating leverage risks. Dr. Evans maintained that the minimum return margin supplements and is consistent with the rate of return on rate base approach and avoids the potential for "double recovery" of capital.[110]

EPGI's application of Dr. Evan's method yielded the following results for 1999 and 2000:

- For 1999, an increase in the traditional return of $0.5 million for Clover Bar and an increase of $1.7 million for Rossdale to meet the minimum return standard. The total increase for 1999 was $2.2 million.
- For 2000, no increase was required to the traditional return for Clover Bar. However, an increase of $1.4 million to the traditional return for Rossdale was required to meet the minimum return standard.

LE/RD, ENMAX and the FIRM Customers said that the "unbundling" of EPGI's generating stations prior to commencement of the PPA period is inappropriate; and on an integrated basis, there is no substantial increase in operating leverage risk that would warrant adoption of the minimum return margin method.

EPGI had six comments respecting these arguments.

First, both LE/RD and ENMAX said that station-by-station "unbundling" is not supported in the precedent cited by Dr. Evans in his response to BR-EPGI-18. The question posed by the Board in BR-EPGI-18 did not ask Dr. Evans to supply precedent to support station-by-station "unbundling"; therefore, the observations of LE/RD and ENMAX are not surprising. The Board asked Dr. Evans to address changes subsequent to Decision U97065 that might now justify a finding of increased operating leverage risk and "...more than double the normal rate of return on older assets such as Clover Bar and Rossdale."[111]

Second, in his response to BR-EPGI-18, Dr. Evans outlined five changes of circumstance that now require a revisiting of the operating leverage concept and method of regulation. The second of these changes bears on the question of "unbundling."

> ...in the PPA world – which was not in prospect in 1996 – the focus is on the plant or unit level. The common equity investor in 1999/2000 is concerned not only about risks during 1999/2000 but also about the long-run risks and returns of individual plants or units during the PPA period. The investor must receive fair

[110] Exhibit 4, p.3-4
[111] BR-EPGI-18

> compensation on a plant-by-plant basis in order to respect the stand-alone concept, because PPAs are expected to be created on either a plant-by-plant or unit-by-unit basis.[112]

Owners of plants may, in future, decide to sell those facilities to third parties. It is not inconceivable that a competitive market might develop for ownership of new and old generating assets. But the ability to sell existing generating assets into such a market depends, in part, on the level of compensation being fixed on a stand-alone basis for each generating asset. If the capital compensation for operation of Genesee were viewed as "adequate incentive" for EPGI to continue to operate Rossdale and Clover Bar, then the anti-competitive impact of providing no stand-alone compensation in respect of Rossdale and Clover Bar is that such generating assets would have little or no value to third parties in a competitive market. The cross-subsidization of Rossdale and Clover Bar by Genesee is inconsistent with the promotion of deregulation and competition at the generating station level.

None of the Intervenors address the coupling of the required "unbundling" to the long-run investment horizons of investors and therefore the need to focus on circumstances during the PPA period when EPGI's generating stations will be considered separately. None of the Intervenors address the problems that arise if owners of plants sell those facilities to third parties. None of the Intervenors addressed the cross-subsidization issues that arise if, say, returns on Genesee are used to "support" the financial viability of Clover Bar and Rossdale. None of the Intervenors addressed the fact that "The cross-subsidization of Rossdale and Clover Bar by Genesee is inconsistent with the promotion of deregulation and competition at the generating station level." In short, none of the Intervenors address the evidence of Dr. Evans on the subject of "unbundling."

Third, Dr. Evans stated:

> Information Request BR-EPGI-18 infers that EPGI should be satisfied by a normal rate of return from Genesee in exchange for little or no compensation for operating Clover Bar and Rossdale. This suggestion is contrary to the stand-alone principle as applied to the circumstances of 1999/2000 and the PPA period.[113]

None of the Intervenors addressed the question of whether or not the stand-alone principle has been violated in the manner described by Dr. Evans.

Fourth, LE/RD and ENMAX said that Dr. Evans cited no precedent in his response to BR-EPGI-18; but they ignored the precedent cited by Dr. Evans in his rebuttal evidence. This precedent deals with applications of the stand-alone concept to a variety of real-world circumstances. Dr. Evans concluded:

---

[112] BR-EPGI-18, p.43-44
[113] BR-EPGI-18, p.44

> The common thread that runs through each of these applications of the stand-alone concept is that stand-alone is applied *on the level at which a separate revenue requirement must be developed.* Exceptions to this general conclusion may arise if all of the activities within a company are of similar risk and if those risks can be compensated for using the same regulatory method. This exception does not apply in the circumstances of Genesee, Rossdale and Clover Bar. [114]

None of the Intervenors addressed Dr. Evans' evidence and precedent respecting the stand-alone concept, its applicability in the context of separated revenue requirements and therefore its applicability to the circumstances of EPGI.

Fifth, both Dr. Bridgeman and Dr. Evans indicated that, even in the absence of the prospective PPA regime, "separated" 1999/2000 revenue requirements must be developed to establish unit reservation prices.[115] None of the Intervenors addressed the nexus between this requirement and the need to "unbundle" the revenue requirements of the generating stations.

Sixth, LE/RD and the FIRM Customers cited the evidence of Mr. Marcus. Aside from the general comment that the "unbundling" of EPGI is "premature" – a matter dealt with above – Mr. Marcus' evidence on "unbundling" essentially consists of the unfounded assertion that EPGI "...is not going to shut down its individual stations pending an IAT contract absent some catastrophic event."[116]

EPGI stated that there was no basis for Mr. Marcus' claim. As explained by Dr. Evans:

> Neither Mr. Marcus nor myself can speak for EPGI. If, however, the Board and the IAT do not provide reasonable compensation for the operation of Rossdale and Clover Bar even when their net original cost rate bases have "vanished", then EPGI will have a substantial incentive to close and decommission these facilities. To do otherwise would constitute a violation of the principle that economic participants make decisions "at the margin" rather than "on the average.[117]

To summarize, each of EPGI's generating stations should be considered separately for revenue requirement purposes. Such consideration is consistent with:

- the need to determine unit-specific reservation prices and UOPs;
- the sale of PPAs on a station-specific basis;

---

[114] Exhibit 39, p.26
[115] Exhibit 4, p.3-4; Tr. p.601-602
[116] Exhibit 159, p.20
[117] Exhibit 39, p.27

- the avoidance of cross-subsidization among generating stations which would otherwise be inconsistent with the promotion of competition at the generating station level;
- the long-run view of investors that unavoidably requires consideration of circumstances in the PPA period even when the determination of rates is for 1999 and 2000; and
- the stand-alone concept of regulation as applied in a variety of circumstances.

Board Findings

The Board agrees with the Intervenors that it is premature to implement the minimum return method in 1999 and 2000. The Board agrees with TransAlta's submission:

> To the extent possible, the allowed cost of capital should reflect the risks of the period corresponding to the period the rates are to be in effect. Shareholders would be over or under compensated if the cost of capital were based upon risks for a subsequent period.[118]

The Board notes that even though investors have a longer time horizon than two years, investors appropriately weigh the risks involved for the years 1999, 2000 and for the years beyond. The reality is that EPGI's generating plants are regulated on a bundled basis for 1999 and 2000 and will be unbundled for 2001 and onward. The Board does not consider that operating leverage is a problem for EPGI on a bundled basis for 1999 and 2000.

The Board considers that conditions in 1999 and 2000 have not changed sufficiently to warrant a change to the Board's findings in Decision U97065 respecting the year 1996. The Board, in Decision U97065, found as follows:

> The Board considers that operating leverage on a GENCO basis or an integrated utility basis has not changed as a result of restructuring. The Board agrees that there may be an increase in operating leverage over time that would increase the GENCO's business risk. However, the Board considers that GENCO and the integrated utility are far from the point where operating leverage risk becomes material.[119]

With respect to EPGI's argument that the EU Act requires unit specific reservation prices, the Board considers the past practice of allocating the corporate return to each unit satisfies the requirements of the EU Act. The Board notes that the additional accuracy of determining a composite rate of return by unit does not change each DISCO's share of reservation payments and, therefore, does not affect the fixing of just and reasonable customer rates for 1999 and 2000.

---

[118] TransAlta Reply, p.85

[119] Decision U97065, p.198-199

Accordingly, the Board rejects EPGI's proposal to implement the minimum reserve margin for Rossdale and Clover Bar in 1999 and 2000. Therefore, the Board directs EPGI, in its refiling, to remove the minimum return margin for Clover Bar and Rossdale for 1999 and 2000.

(c) Cash Operating Expense

(1) Dragline Operating Benefits

EPGI included an adjustment to its fixed fuel costs of $2.84 million in each of 1999 and 2000 in recognition of operating benefits associated with the operation of the Marion 8750 dragline at the Genesee mine.

In the 1994 EEMA forecast proceeding, the Board ruled, in Decision E93094, on the prudence of EPGI's investment in the M8750 dragline, disallowing certain costs associated with the sizing and timing of the purchase. In the 1995 forecast proceeding, EPGI sought to advance evidence in the form of a cost benefit analysis demonstrating that the disallowance of costs associated with the sizing of the M8750 dragline was in error. At a pre-hearing conference the Board indicated that the issue of prudence of the M8750 dragline should be dealt with in another forum.

To date, EPGI had not formally pursued this matter with the Board. However, EPGI, noted in the Settlement Agreement dated 25 February 1997 filed with the Board in respect of the 1995 EEMA Adjustment, that there was evidence of operating efficiencies, which had been gained through the sizing of the M8750 dragline, not taken into account by the Board. EPGI also noted that operating efficiencies associated with the M8750 dragline were well recognized.

As part of EPGI's 1995 EEMA Settlement Agreement with interested parties, EPGI agreed that it would not pursue the matter of operating benefits associated with the selection of the M8750 dragline for 1995, 1996 and 1997. As a consequence of this agreement, EPGI stated that it had foregone the sum of $7.3 million for 1995, 1996 and 1997 of the estimated $27 million in operating benefits (both net present value (NPV) in 1995 dollars).

EPGI and interested parties agreed to the treatment of the FCL portion of the dragline disallowance as set out in EPGI's letter to the Board dated 10 March 1997 in respect of the 1995 EEMA Adjustment negotiated settlement agreement. In that letter, EPGI advised the Board that parties had agreed that the total $15.46 million disallowance was to be amortized over a period of 7.2 years, with the amortized amount of $2.9 million being deducted from EPGI's fixed fuel cost from 1996 onward.

In response to SPPA-EPGI-08(e), EPGI provided the total budget amounts set for the Joint Venture and set out the payments required by FCL for mine costs. As the dragline disallowance was only attributable to EPGI, the FCL costs did not include the disallowance.

EPGI commissioned John T. Boyd Company (Boyd) to prepare a comparison of costs at the Genesee mine assuming a variety of alternative combinations of draglines, and production levels. The Boyd Report was included as Appendix G in the Application. The results of that Report were summarized in Table 4 of EPGI's evidence.[120] Boyd concluded that the higher capital costs of the M8750 were essentially offset by lower operating costs over the life of the Genesee mine.

The Intervenors rejected EPGI's request for $2.84 million in recognition of the annual operating benefits derived from operating the M8750 dragline.

The Intervenors raised several issues with respect to EPGI's request for annual operating benefits of $2.84 million as follows:

- the Board's jurisdiction.
- the relevance of the Boyd Report, and
- the value of the operating benefit.

(A) The Board's Jurisdiction

Position of the FIRM Customers

The FIRM Customers submitted that, subsequent to Decision E93094, EPGI outlined its position regarding the disallowance and the interpretation of this Decision in a letter to the Board dated 22 August 1994:

> Since the pre-hearing conference, Edmonton Power has approached TransAlta and Alberta Power to get a better understanding of their interpretation of compliance with E93094. Based on that understanding, Edmonton Power is prepared to amend its filing to propose a rate base value that should, it is hoped, remove contentious issues related to E93094 from this proceeding. If the Board decides Genesee 1 should be placed in rate base on January 1, 1995, at that value, Edmonton Power will consider that the end of the matter and have no further interest in reconsideration of Decision E93094.[121]

The FIRM Customers stated that EPGI requested that the Board reconsider Decision E93094 without making a formal application for review and variance. The FIRM Customers also noted the $2.84 million amount was included in EPGI's PPA proposal through to the year 2020.

The FIRM Customers indicated the question of dragline sizing first arose in the 1994 EEMA forecast proceeding. Based on its own analysis, the Board concluded the combination of an

[120] Exhibit 2; Table 4, p.13
[121] Tr. p.911

M8200 dragline (previously acquired) and the M8750 dragline resulted in approximately 50% excess stripping capacity. The Board Decision stated:

> ...at this level, the evidence ..... indicates the combined dragline utilization is expected to reach no more than 55% during the life of the Genesee mine.....the Board considers EP knew, or should have known at the time it ordered the second dragline in 1989 that there would be a significant under-utilized capacity with the addition of this dragline in 1994.[122]

The FIRM Customers stated that the Board's Decision was based on a comprehensive review of comparative capital and operating costs for the M8750 compared to other relevant alternatives and included consideration of the surrebuttal evidence of EPGI prepared in response to the evidence of TransAlta.

The FIRM Customers stated that the Board, having determined the acquisition was not prudent, conservatively reduced the cost of the M8750 dragline by 30% to reflect the 50% excess capacity and rounded down the resulting amount of $11.9 million to $10.0 million. In addition, the Board directed EPGI to reduce Fording's cost of coal to reflect the exclusion of $10.0 million from Fording's one-half interest in the M8750 dragline.[123] The FIRM Customers indicated these amounts were in addition to the Board's penalty imposed with respect to the timing of the acquisition of the M8750 dragline, which was ultimately determined to be $5.4 million for each of EPGI's and Fording's share.[124] The FIRM Customers stated that this penalty was intended to result in a total reduction of approximately $30.8 million in the capital cost of the dragline to EPGI.

The FIRM Customers noted the Board gave recognition to both capital and operating costs of the various alternatives in its decision. The FIRM Customers submitted operating costs were taken into account and the rather conservative nature of the write-down provided implicit recognition of these operating benefits.

The FIRM Customers noted the matter was again raised by EPGI in the 1995 EEMA Forecast proceedings. The FIRM Customers stated that, in refusing to reconsider the sizing and timing issues regarding the M8750, the Board, in its decision, made the following comments:

> At the July 14, 1994 pre-hearing conference, and as confirmed subsequently in the Board's July 18, 1994 letter to EP, the Board ruled that the findings made in Decision E93094, related to prudence issues concerning the dragline, coal-handling facility and 1988 release of manufacturing holds, would not be accepted by the Board as issues in the 1995 EEMA Forecast proceedings. The Board

[122] Decision E93094, p.215
[123] Decision E93094, p.217
[124] Decision E94095, p.27

> stated that the procedure to deal with matters decided in Decision E93094 could be by means of '...a separate application (or applications) for review and variance pursuant to section 56 of the Public Utilities Board Act...'.[125]

The FIRM Customers asserted that no such application was initiated by EPGI and, during the course of cross-examination, EPGI stated "...we are at peace with that decision. We are not challenging it."[126] However, the FIRM Customers concluded if EPGI's proposal were to be accepted, it would undo the Board's previous decision and eliminate the penalty which was based on both timing and sizing issues.

As the FIRM Customers understand, the Board's obligations, under the EU Act, are to approve a tariff which provides the electric Utility with a reasonable opportunity to recover its prudent costs associated with generation. The FIRM Customers have interpreted costs to include operating and maintenance costs (forecast to be incurred), return of and on capital and income tax (i.e. the "cost of service"). In the Alberta Cost of Service Inquiry,[127] the Board made the following statement regarding Revenue Requirement:

> The total cost of service for any particular regulated company should be the total Revenue Requirement of the company. The total cost of service or total Revenue Requirement includes the following components:
>
> 1) Cash Operating Expenses
> 2) Non Cash Operating Expenses (primarily depreciation)
> 3) Income Taxes
> 4) Return

The FIRM Customers were not aware of any circumstances in which the EUB (or its predecessor, the Public Utilities Board) had included in revenue requirement, costs which have not or will not be incurred by the Utility. The FIRM Customers found it inappropriate when the "operating benefits" were calculated using a hypothetical base case and were not identified in any line item within the application.

The FIRM Customers submitted there was no factual or legal justification for EPGI's proposal and should, therefore, be rejected. Based on the statement summarizing EPGI's position "...there is clear evidence of significant operating efficiencies which have been gained through the sizing of the M8750 dragline which were not taken into account by the Board,"[128] the FIRM Customers assumed this was a thinly veiled attempt to review and vary the Board's decision made more than five years ago. The FIRM Customers stated that, if approved, the proposal

[125] Decision E94095; p.25
[126] Tr. p.908
[127] Report E78100, p.75
[128] Exhibit 2, p.13

would set a precedent enabling Utilities to recover not only the actual cost of service (including return of capital) but also normal and expected reductions in operating costs resulting from the efficiencies created. The FIRM customers reiterated that, in a cost of service jurisdiction this recovery should not be allowed.

Position of ENMAX

ENMAX stated that, in Decision E93094, the Board disallowed a portion of the capital costs of the M8750 dragline. ENMAX indicated EPGI acknowledged that it did not have any concerns with the decision.[129] However, ENMAX submitted that EPGI's filing for the recovery of disallowed costs by fabricating a conceptual benefit based on EPGI's perceived lower operating costs associated with the M8750 was quarrelling with the decision.

ENMAX stated that EPGI's Application was based on its interpretation of Decision E93094 in which the Board "dealt with capital costs, disallowance, and did not deal with the operating benefits."[130] When specifically directed to a schedule in that decision, which included both capital and operating costs of the draglines,[131] EPGI agreed that the capital and operating cost information was before the Board but EPGI interpreted that the Board focussed on the excess capacity of the M8750.[132] ENMAX asserted that EPGI's interpretation was far-fetched because at page 209 of Decision E93094 the Board stated:

> The Board considers that the selection of the appropriate equipment hinges on the net present value of capital and operating costs of the various alternatives.

Despite EPGI's attempt to lead evidence on the interpretation of the Board's deliberations, ENMAX submitted the preceding quote confirmed that the Board considered both capital and operating components in evaluating the selection of the M8750 dragline.

Position of LE/RD

LE/RD indicated that EPGI proposed to recover, as part of its mine expense, operating benefits that have accrued as a result of the over-sizing of the dragline. LE/RD do not disagree, based on the principle that customers should not have the benefits arising from the capital disallowance or the benefits of the over-sizing arising from the more efficient operation of the dragline.

LE/RD noted that some Intervenors took the position that because the Board dealt with operating benefits associated with the dragline in previous hearings, and because EPGI had not sought a review and variance of those decisions, EPGI could not raise that issue. However, LE/RD submitted that, although EPGI had not previously asked for a cost recovery of the operating

[129] Tr. p.958
[130] Tr. p.958
[131] Exhibit 45, p.192
[132] Tr. p. 962-963

benefits, LE/RD would have some difficulty with the proposition that EPGI was not entitled to seek that recovery.

LE/RD agreed with arguments that reduced reservation payments, but indicated such reductions must be measured based on the principles of reasonableness and fairness. LE/RD agreed with EPGI, that while the Board considered operating benefits in prior hearings, LE/RD assumed that consideration was from the point of view of determining if operating benefits exceeded the costs of over-sizing for the purpose of deciding if it was prudent to oversize the dragline. The Board concluded that the operating benefits did not exceed the cost of over-sizing. LE/RD submitted that decision was supported by material, provided in response to a Board question in this proceeding, which disclosed the costs to consumers, by including the excluded costs in rate base, were greater than the claimed operating benefits.

LE/RD submitted that EPGI acknowledged that a portion of the requested levelized cost was related to operating benefits for the year 1998. LE/RD asserted that to include the 1998 costs offended the principles of prospective rate-making and recommended that, should the operating benefit charge be permitted, EPGI should be directed to recalculate the charge so as not to include any sum associated with recovery of the 1998 operating benefits.

Position of EPGI

EPGI stated that the FIRM Customers stopped short of saying that the Board would be outside its jurisdiction in approving the dragline operating benefit. The FIRM Customers knew that the Board has broad discretion in approving the "prudent costs associated with generation..."[133] EPGI submitted the inference that the Board was without jurisdiction in this matter was therefore specious.

EPGI claimed the FIRM Customers' indication they were not aware of any circumstances, where the Board had included costs which were not or would not be incurred by the Utility, was an unstated inference that the dragline operating benefit in EPGI's revenue requirement was outside the Board's jurisdiction. EPGI concluded the FIRM Customers' statement was made in error. EPGI cited two examples of Board decisions:

- As explained in EPGI's final argument, the Board, in Decision E93094,[134] explicitly subtracted forecast operating savings from the $9.9 million disallowed in respect of the Genesee coal handling facility.
- In Decision E81014, the Board approved a surcharge on the gas bills of customers in the Municipality of Crowsnest Pass to reflect the difference between Canadian Western Natural Gas Limited's purchase price for the Coleman gas system and the net book value

[133] EU Act, Section 52(1)(b)
[134] p.229

> of the assets.[135] The Board approved the surcharge after consideration of certain benefits arising from the acquisition by Canadian Western and accruing to the residents of Crowsnest Pass.

EPGI submitted that the Board should reject the FIRM Customers' inference that it lacked jurisdiction to approve the inclusion of the dragline operating benefit. The Board should also dismiss the FIRM Customers' incorrect assertion that the Board had never "...included in revenue requirement, costs which have not or will not be incurred by the Utility."

In addition, EPGI submitted that arguing the Board explicitly considered operating benefits in determining the dragline capital cost disallowance, the FIRM Customers suggested that the Board, by implication, took account of the operating benefits. The FIRM Customers stated:

> Having determined the acquisition was not prudent, the Board conservatively reduced the cost of the M8750 dragline by 30% to reflect the 50% excess capacity and rounded down the resulting amount of $11.9 million to $10.0 million. [136]

EPGI disagreed with the suggestion of an implied mitigation of the disallowance reduction.

- The Board used 30% because there was "...no evidence before it to indicate what a dragline with about 50% of the stripping capacity of the M8750 would cost,"[137]
- The Board rounded the disallowance down to $10.0 million, because there was "...difficulty inherent in estimating a precise dollar amount of reduction...,"[138] and
- There was no suggestion in Decision E93094 that the Board was being "conservative" because of the existence of operating benefits associated with the M8750 dragline.[139]

EPGI submitted the Board disallowed a portion of the M8750 dragline in Decision E93094.[140] EPGI noted that the FIRM Customers characterized EPGI's Application as "...a thinly veiled attempt to review and vary the Board's decision..."[141] EPGI also noted ENMAX's statement "In essence, EPGI is quarrelling with decision E93094."[142]

EPGI asserted that both ENMAX and the FIRM Customers were wrong. EPGI stated at Tr. p.871:

---

[135] Decision E81014, p.14-19
[136] FIRM Customers Argument, p.108
[137] Decision E93094, page 216
[138] Decision E93094, page 216
[139] Decision E93094, pages 215-216
[140] p.216
[141] FIRM Customers Argument, p.110
[142] ENMAX Argument, page 93

> So we are not going back and contesting the decision. We are not commenting on the capital costs at all. We are simply identifying that there are reductions in operating costs that stem from the capacity of that dragline, and we are seeking to have that recognized in this particular filing.

And again at Tr. p.908:

> ...certainly the company does not agree with the Board's decision on disallowance of the capital, but we accept that decision, and we are not contesting it here. We see the recognition of the operating benefits as a separate matter, and we are at peace with that decision. We are not challenging it.

And again at Tr. p.910:

> ...we haven't filed an application for a review and variance, and we are not questioning that decision now.

And again at Tr. p.915:

> ...but again, Mr. Bryan, just to restate it for your benefit and the Board's benefit, whatever the Board decided back then, we are not contesting that anymore, and we are living by that Board decision and not taking that up with the Board.

And finally, Dr. Lewin stated at Tr. p.957 and 958:

> I think, Mr. Chairman, if I might just add a comment there. If you look at my August 24, 1994, letter on the issue of the industry solution, I think we called it in those days, we said that if the Board were to concur with what was stated there on the industry solution, then we would have no further concerns regarding E93094, and we still hold to that decision. E93094, in our minds, dealt with capital costs, disallowance, and didn't deal with operating benefits. So we have no concerns, no issue with E93094 at all.

EPGI stated it was not seeking a review and variance of Decision E93094 "thinly veiled" or otherwise. EPGI submitted the FIRM Customers attempted three variations on its review and variance argument when confronted with EPGI's statements.

First, the FIRM Customers stated:

> However, if EPGI's proposal were to be accepted, it would undo the Board's decision and eliminate the penalty which was based on both timing and sizing issues.[143]

EPGI claimed the FIRM Customers' statement was wrong. EPGI was not seeking a Board order to reverse either the timing or sizing components of the capital cost disallowance set out in Decision E93094. EPGI was not seeking to charge customers for operating cost benefits that were enjoyed but not paid the M8750 came into service. EPGI indicated the benefits for 1995, 1996 and 1997 totaled 7.3 million 1995 dollars[144] and the $2.84 million was an annualized value that yielded a net present value of 19 million 1995 dollars; i.e., $27 million of lifetime operating benefits less the operating benefits associated with 1995, 1996 and 1997 that were retained by customers.[145]

In order to conclude that EPGI's present application would "undo the Board's decision and eliminate the penalty," EPGI suggested the Board would have to approve revenue requirements sufficient to recover both the past and future benefits. EPGI made no such application. EPGI submitted the sole purpose of the EPGI proposal was to reflect, in reservation payments on a prospective basis, the operating cost benefits that customers were enjoying and would continue to enjoy but were not paying for now. The FIRM Customers' assertion respecting elimination of the "penalty" in Decision E93094 was, therefore, incorrect.

EPGI noted, that the Board recognized during the hearing that approval of EPGI's present Application would not be sufficient to "eliminate the penalty" imposed in Decision E93094.[146]

EPGI noted that, in the FIRM Customers' second variation on the review and variance argument, it suggested that, in computing the dragline capital cost disallowance, the Board explicitly took into account the prospective operating benefits; thereby, reducing the amount of the disallowance. EPGI submitted the inference was that if the Board, in Decision E93094, had already taken into account the prospective operating benefits, then EPGI's Application would essentially constitute a review and variance of that decision.

---

[143] FIRM Customers Argument, p.109
[144] EPGI Application, p.13
[145] Tr. p.905-906
[146] Tr. p.958

EPGI stated in argument that:

- The Board could not reach a conclusion in Decision E93094 regarding the operating benefits of the M8750 dragline due to the conflicting and contradictory evidence on that record,
- The disallowance was related to the Board's appraisal of the unused capacity of the dragline and did not take account of either avoided capital expenditures or avoided operating costs, and
- If the Board had considered dragline operating cost benefits in its computation of the appropriate disallowance, as theorized by ENMAX and the FIRM Customers, then the Board would have made an explicit adjustment for such benefits as it had in the same decision in respect of the Genesee coal handling facility.

EPGI was astonished that ENMAX would make a claim that EPGI was "...expecting to achieve the recovery of disallowed costs by fabricating a conceptual benefit based on its perceived lower operating costs associated with the M8750"[147] when the existence of these lower operating costs is a recognized and accepted fact, considering that:

- The Boyd Report documented these benefits in substantial detail,
- Mr. Berkinshaw of AE acknowledged the existence of such benefits in the 1996 GTA proceeding,[148] and
- ENMAX provided no contrary evidence.

EPGI submitted that the Board should reject the ENMAX "fabrication" claim as inflammatory, inaccurate, unsupported and inconsistent with the evidence on this record and the record of the 1996 GTA.

EPGI indicated the agreement of LE/RD when they observed:

> While the Cities are sympathetic to arguments that will reduce their obligations with respect to reservation payments, such reductions must be measured based on the principles of reasonableness and fairness. The Cities agree with EPGI that while the Board did consider operating benefits in prior hearings, that was from the point of view of determining if operating benefits exceeded the costs of oversizing for the purpose of deciding whether it was prudent to oversize the dragline. The Board concluded that they did not. In fact that decision is supported by material provided in response to a Board question in this proceeding which disclosed the costs to consumers of including the excluded costs in rate base is greater than the claimed operating benefits. However, EPGI has not previously asked for alternative relief, being recognition as a cost recovery of the

[147] ENMAX Argument, p.93
[148] Tr. 5271, 1996 GTA Proceeding

value of the operating benefits, and the Cities would have some difficulty with the proposition that they are now disentitled to seek that recovery. [149]

EPGI submitted that there was no evidence to support the assertion that the Board, in Decision E93094, reduced the dragline disallowance to reflect forecast operating benefits.

EPGI submitted that the Board recognized that there likely was not a one-to-one correlation between the percent over-sizing of the dragline and the resulting costs were a smaller capacity dragline purchased. The Board also recognized there might be certain constraints with respect to engineering and design that would not change with a smaller sized dragline. The analysis indicated the dragline was over-sized by about 50% using the Board approved forecast of 2.9 million tonnes/year coal production. The Board had no evidence before it to indicate what a dragline, with about 50% of the stripping capacity of the M8750, would cost.

EPGI submitted that there was no implied mitigation of the dragline disallowance related to operating benefits and summarized that EPGI was not seeking a review and variance of Decision E93094. EPGI recommended the arguments of the FIRM Customers and ENMAX should be rejected.

Board Findings

The Board, when first considering the M8750 dragline, compared the additional capital cost of the larger dragline with the anticipated operational benefits from employing the dragline for the purpose of deciding if it was prudent to oversize the dragline. The Board determined that the potential savings resulting from over-sizing did not offset the additional capital cost.

The Board concluded, in Decision E93094, that the combination of an M8200 dragline and the M8750 dragline resulted in approximately a 50% excess stripping capacity. The Board, accordingly, reduced the capital cost of the M8750 dragline by 30% which, when rounded down, resulted in a $10 million reduction to the dragline cost for rate base purposes. This $10.0 million reduction also applied to Fording Coal when determining the cost of coal to be paid by EPGI. In addition to the capital cost reduction for over-sizing, the Board imposed a penalty with respect to the timing of the dragline purchase, resulting in a further reduction to the capital cost of the M8750 dragline, for rate base purposes, of $5.4 million each to EPGI and Fording Coal.

The Board considers the intent of Decision E93094 was to determine a value to be placed on the over-sizing and timing of the purchase of the M8750 dragline, that the Board considered to be imprudent. In so doing, the Board did not consider any benefits through the operations of the M8750 dragline as a component of the cost increase or reduction to the M8750 dragline for rate base purposes.

[149] LE/RD Argument, p.18

In this Application, the Board notes that EPGI has been very clear that there is no request for a review and variance of Decision E93094, but rather only a consideration of the benefits the customers are receiving, but not paying for, through the use of the M8750 dragline. The Board notes that EPGI's Application does not request any change to the original capital cost of the dragline for rate base purposes.

The Board does not agree with the FIRM Customers that there is no factual or legal justification for EPGI's proposal, or with ENMAX that EPGI's interpretation of E93094 is far-fetched. The Board agrees with LE/RD and EPGI that benefits have accrued to the customer through the use of the M8750 dragline and that, even though EPGI has not previously asked for a recovery of operating efficiencies, EPGI is entitled to request such recovery.

The Board finds that EPGI's Application does not constitute a review and variance application. The Board considers that, under section 52(1)(b) of the EU Act, it has the necessary jurisdiction to determine if operating benefits associated with the M8750 dragline exist and, if so, to what extent.

(B) Relevance of the Boyd Report

Subsequent to Decision E93094, EPGI requested John T. Boyd Company (Boyd) to assess the differences in capital and operating costs, if any, using the current stripping equipment complement (including the M8750 dragline) versus that of alternative dragline combinations using a second, smaller dragline consistent with the Decision.

The Boyd Report compared alternative equipment complements based on the original forecast demand for coal of 2.9 million tonnes per year (mty) and on the current coal requirements of 3.5 mty. The original forecast coal production of 2.9 mty, as approved in Decision E93094, was based on the configuration and capacity of the Genesee draglines which were designed to reliably meet anticipated coal burn requirements of the two-unit Genesee Generating Station at that time. Subsequent to the commissioning of the second generating unit in 1994, the actual tonnes produced were recorded as 3.35 mty in 1994, 3.46 mty in 1995 and 3.54 mty in 1996.

The Report consisted of 3 cases for each annual coal requirement. The first case or Base Case set out the costs using the current dragline complement of the M8200 and M8750 draglines. The second case, or Notional Case A, assumed the mine was equipped with the first M8200 dragline and a second, identical M8200 dragline in place of the M8750. And the third case, or Notional Case B, assumed the mine was equipped with the first M8200 dragline and a second, hypothetical machine having the working dimensions of the M8750 but only 50% of the capacity. The Boyd Report summarized the savings as follows:

2. EPGI
(c) Cash Operating Expense

	$ million					
	2.9 mty			3.5 mty		
Case	Base Case	Case A	Case B	Base Case	Case A	Case B
Initial capital	143	106	119	143	106	119
Future capital	134	160	150	177	210	226
Total capital	277	266	269	320	316	345
Future operating	418	497	472	537	625	637
Total	695	763	741	857	941	982
Savings	-	68	46	-	84	125

The FIRM Customers

The FIRM Customers submitted that the comparative figures, shown in the Boyd Report, were based on the "actual case," using of the M8750 and M8200 draglines and a "hypothetical case" using two M8200 draglines.[150] The FIRM Customers noted the hypothetical case was not one considered directly by the Board nor was there any identified reason for selecting it as a base case when compared to the many alternatives which were actually considered or might otherwise be available for consideration.[151]

The FIRM Customers observed there were a variety of alternatives available and the selection of an alternative and the underlying assumptions would have a material impact on the results. The FIRM Customers submitted that even if such a comparison were appropriate, the Board's comments, in Decision E93094 at page 211," the above analysis demonstrates the sensitivities in the use of different assumptions and the difficulties inherent in attempting to assess the economics of the two alternatives" apply equally to the current analysis.

The FIRM Customers stated the Boyd Report was nothing more than a re-visiting of the evidence on capital and operating costs presented to the Board in the 1994 EEMA Forecast proceeding. The FIRM Customers stated, in that proceeding, EPGI provided evidence as to the various alternatives thought to be appropriate for consideration of the Board and provided particulars of both the capital and operating costs of those alternatives. The FIRM Customers submitted that EPGI's current evidence addressed the same issues considered and resolved by the Board, which could be described as *res judicata.*

[150] Notional Case A in the Boyd Report
[151] Tr. p.925

The FIRM Customers stated that whether or not the Boyd Report was accepted, it should be recognized as an estimate of the reduction in annual operating costs of FCL. The FIRM Customers submitted there was no evidence before the Board which would confirm all or any part of the $2.84 million reduction accrued to EPGI or passed on to end use customers through the UOPs or Reservation Price.[152] Having regard to the lack of evidence and the confidential nature of the Fording Coal contract, the FIRM Customers submitted assumptions regarding the quantum of operating benefits, if any, would be inappropriate.

Furthermore, the FIRM Customers stated the Board adjustments, regarding the dragline sizing in Decisions E93094 and E94095, were part of overall reductions respecting both timing and sizing of the dragline, the boiler and the coal handling facilities. The FIRM Customers submitted that dealing with EPGI's half of the dragline in isolation was inappropriate.

Position of ENMAX

ENMAX noted EPGI's lack of detailed cost information that had been requested but not provided and suggested if the information had been provided, then such information may have lent credibility to the allegations of a benefit and parties might have had confidence that the Boyd report was prepared without bias. ENMAX submitted the onus was on EPGI to demonstrate that no bias existed and that onus had not been discharged.

ENMAX indicated that Notional Case B was not a valid comparison and suggested that EPGI acknowledged a machine such as the one used in Notional Case B did not exist, nor was such a machine even in the design phase.[153] ENMAX submitted that the inclusion of a case based on a mythical machine only served to cloud the issue.

ENMAX stated the Boyd Report did not use data consistent with that provided in the Application. Moreover, ENMAX was concerned that the data provided bore no relationship to actual experience as was acknowledged in response to ENMAX-EPGI-32 (k), "[t]he values in the Boyd report were developed on a different basis and for a different purpose than those included in EPGI's GTA." ENMAX submitted this inconsistency impacted the present value of capital costs. ENMAX further stated, as confirmed by EPGI, the industry norms used by Boyd in its evaluation of the costs of the mine operations would be reflected in ranges based on scatters of data.[154] ENMAX submitted that neither the Boyd report nor the Application attempted to demonstrate the sensitivity of the end result to ranges of the data.

Lastly, ENMAX indicated that no assumption had been made for increased productivity of replacement capital (technical advances) during the pit progression. ENMAX submitted that if that assumption had been made, the operating costs would have been lower in the progression of

[152] Tr. p.944
[153] Tr. p.900
[154] Tr. p.952-953

years in the analysis. While EPGI advised observing the bottom line, ENMAX submitted taking such advice would be ill-advised based on the discontinuities in the Boyd evidence.

Based on the foregoing, ENMAX submitted that the Boyd report could not be relied upon to verify the existence of a benefit that EPGI claimed was conferred upon DISCOs as a result of the use of the M8750 dragline.

ENMAX stated that EPGI misused and misinterpreted the Boyd Report as the report discussed the difference in operating and capital costs under three options dictated to it by EPGI.[155] More specifically, ENMAX suggested Boyd understood its terms of engagement as follows:

> Subsequent to the PUB decision, Edmonton requested that John T. Boyd Company (BOYD) independently assess the differences in capital and operating costs, if any, using the present stripping equipment complement (including the 8750) versus that of alternative dragline combinations using a second (smaller) dragline consistent with Decision E93094 of the PUB.

ENMAX alleged EPGI cherry-picked the operating costs and disregarded the impact of the capital costs to suit its purpose.[156] ENMAX stated the $27 million saving was restricted to a comparison of operating costs using a discount rate of 8% which, when having regard to a single cost stream in a comparison of alternatives on a net present value basis, was a fundamental flaw in EPGI's analysis.

ENMAX alleged the misuse of the report was underscored when the details were reviewed. ENMAX stated the Boyd report did not highlight, single out or even identify the $27 million saving. Rather, ENMAX suggested the Boyd report, in its Executive Summary, drew attention to a differential benefit based on both operating and capital costs and the selected savings were based on a 6% discount rate. ENMAX concluded that was the only scenario for which there was a net saving on a combined capital and operating basis.[157]

ENMAX submitted that EPGI arbitrarily plucked a $27 million differential, based solely on operating costs, using an 8% discount rate and attributed the analysis in its expert's report to its own derivation of a $2.84 million addition to annual revenue requirement. ENMAX submitted EPGI's discount rate adopted the middle of the range offered by the Boyd report.[158] Had EPGI adopted the appropriate analysis of total operating and capital, as done in the Boyd report, and maintained the selection of a discount rate, ENMAX submitted then, the resulting savings would be negative $1 million according to Table 2.1 in the Boyd report.

---

[155] Tr. p.882
[156] Tr. p.892- 893
[157] Boyd Report, p.2-5
[158] Tr. p. 904, 906-907

ENMAX submitted that differing choices on capital and operating projections would have offsetting impacts. ENMAX asserted it was apparent the added emphasis on earlier replacement of parts would generally result in lower maintenance costs or, alternatively, added emphasis on maintenance could defer expenditures on capital.

ENMAX conveyed a proper costs/benefit analysis should have used both capital and operating costs. ENMAX stated that the Board articulated its requirement to review both capital and operating costs in a net present value of various alternatives.

Based on the foregoing, ENMAX proffered that:

- EPGI misinterpreted Board Decision E93094 to its own advantage,
- EPGI employed an after the fact analysis selectively on a single asset,
- The Boyd report:
  - lacked critical detailed cost information which may have cost credibility to its report;
  - used an invalid comparison in Notional Case B, and
  - used data that had no relationship to reality;
- EPGI's calculation loaded benefits in 1999 and 2000 of $2.84 million in each year that contradicted the amounts of savings for those years in the Boyd report;
- EPGI's analysis misinterpreted the results of the Boyd studies and selectively used operating costs in an attempt to prove its case; and
- EPGI speculated on the benefits that would be realized.

Position of EPGI

EPGI noted the FIRM Customers questioned the choice of an M8200/M8200 configuration[159] for comparison to the current operating configuration.[160] Mr. Miller considered and rejected truck-shovel alternatives as uneconomic and stated:

> I think another thing, if we just look at what has happened within the province, when a company comes into a mining situation where they have reached the capacity of a single dragline, and you see what they have done next. They have always gone to buying another dragline, so it gives a lot of weight behind that of looking to a second dragline, and you will find that throughout the province and also into Saskatchewan.[161]

EPGI stated the Notional Case A in the Boyd Report was an operating scenario that reasonably matched the Board's reference to a "...dragline over-sized by about 50%..."[162]

---

[159] Notional Case A in the Boyd Report
[160] Base Case in the Boyd Report
[161] Tr. p.925
[162] Decision E93094, page 216

> Notional Case A includes the existing 8200 and assumes a second Marion 8200 dragline of the same size and capacity is purchased in place of the Marion 8750. This second dragline, which is the next smaller size class from the Marion 8750, has slightly over half the production capacity of the 8750.[163]

EPGI indicated that the FIRM Customers also questioned whether the Board's misgivings about the comparisons in the 1994 EEMA Forecast proceeding would not lead the Board to have similar misgivings about the comparisons in the Boyd Report. EPGI submitted that, with no evidentiary support, the FIRM Customers' suggestion that the Board should be equally concerned about the Boyd Report, should be disregarded.

EPGI asserted there was evidence provided. EPGI explained the difficulty in assessing the economics of the two alternatives in the 1994 EEMA Forecast proceeding arose because the operating scenarios proffered by EPGI and TransAlta assumed different production volumes, different discount rates and dissimilar kinds of equipment.[164] EPGI explained that, in contrast, the Boyd Report compared alternative operating scenarios using the same production volumes, the same discount rates and similar kinds of equipment.[165] Thus, EPGI submitted an objective and meaningful comparison was made using the same assumptions for each operating scenario. Based on the argument from the FIRM Customers that the $2.84 million was an estimate of the reduction in annual operating costs of Fording Coal, EPGI implied that the FIRM Customers misunderstood the basis for the $2.84 million.

EPGI explained that Fording Coal operated the Genesee mine and recovered its operating costs from EPGI. EPGI noted the Board had approved EPGI's coal costs from Fording in prior decisions where Fording's costs reflected the operating costs associated with the M8750 dragline; and those operating costs reflected the operating benefits of using the M8750.[166] EPGI stated the Fording operating costs constituted part of EPGI's forecast fixed fuel expense; and therefore, the operating benefits were flowed through to customers in a lower reservation price.[167]

EPGI indicated that the FIRM Customers expected to find a line item in the EPGI Application that showed the $2.84 million benefit and suggested that unless EPGI could point to such a line item, then the Board should disallow the operating benefit. EPGI explained that a $2.84 million line item did not exist and the operating costs from Fording were *net* of the benefit; i.e., customers automatically received the benefit. EPGI submitted that the absence of a line item in its application did not alter the existence or diminish the value of the benefit.

---

[163] The Boyd Report, p.3-8
[164] Decision E93094, p.210-213
[165] EPGI Application, Appendix G, Executive Summary, Table 2.1
[166] Tr. p.946-947
[167] EPGI Application, p.12

EPGI stated it did not propose that the Board "deal with EPGI's half of the dragline in isolation" as submitted by the FIRM Customers. EPGI again alluded the FIRM Customers did not understand the arrangements between EPGI and Fording and the basis on which the Boyd Report arrived at its $27 million operating benefit estimate. EPGI paid 100% of the operating costs of the Genesee mine to Fording as operator of the mine.[168] EPGI stated the $27 million net present value benefit was 100% of the operating benefit associated with the dragline.[169] EPGI was proposing that 100% of the operating benefit be reflected in its revenue requirement, because EPGI's customers were receiving 100% of the benefits in the form of reduced costs.

EPGI stated that ENMAX's concerns with the Boyd Report were unjustified. EPGI indicated that ENMAX's first concern that the Boyd Report and EPGI failed to provide sufficiently "detailed cost information" to verify the existence of operating benefits was unfounded. EPGI submitted the Boyd Reports included:

- annual projected operating costs;
- annual projected capital costs;
- range diagrams;
- detailed volumetrics, and;
- productivity derivations.

When requested by the FIRM Customers, EPGI also provided detailed electrical cost estimates for each of the draglines.[170]

EPGI stated that when ENMAX sought "detailed cost information" through the information request process, EPGI supplied the information as follows:

- ENMAX-EPGI-32(k) provided a reconciliation of costs between the Boyd Report and the 1999/2000 GTA submission for years 1998, 1999, and 2000;
- ENMAX-EPGI-32(m) provided mine operating costs for 1996, 1997, 1998 and forecast 1999 and 2000; and
- ENMAX-EPGI-32 (o) provided a reconciliation between the Boyd operating costs in Table 4.3 with the actual mine operating costs

EPGI suggested the requested information had no bearing on the operating benefits calculation because, by definition, the operating benefits reflected cost differences. EPGI stated the Boyd Report was, therefore, concerned only with costs that differed under the alternative operating scenarios as explained in ENMAX-EPGI-32(k). EPGI explained the information requested by

[168] Tr. p.946
[169] EPGI Application, Appendix G, Boyd Report, Executive Summary, Table 2.1
[170] Exhibit 47, Undertaking at T7:940 and 941

2. EPGI
(c) Cash Operating Expense

ENMAX included total mine capital and operating costs which were not the same as the more limited set of costs shown in the Boyd Report but rather an expanded set of cost estimates which were not necessary to quantify the operating benefits.

EPGI submitted that the Board should reject ENMAX's argument respecting the lack of detailed cost information in the Boyd Report and on the record.

EPGI also considered, as unfounded, ENMAX's second concern that the Notional Case B was not a valid comparison. EPGI stated the Application reflected the capitalization of operating benefits arising from a comparison of the Boyd Report Base Case with Notional Case A as shown in EPGI's Application on page 13 and in Appendix G and in the Boyd Report on the Executive Summary, Table 2.1. EPGI suggested the comparison with Notional Case B was irrelevant in the calculation of the $2.84 million operating benefit therefore, ENMAX's second concern was similarly irrelevant. EPGI refuted ENMAX's contention that EPGI and Boyd sought to "cloud the issue" was misleading and untrue and should be disregarded by the Board.

EPGI stated that ENMAX's third concern was that the Boyd Report did not use data consistent with that provided in EPGI's Application. When ENMAX requested EPGI to reconcile the 1998, 1999 and 2000 capital additions in the Boyd Report with those in the EPGI Application, EPGI provided a detailed explanation of the differences in ENMAX-EPGI.32(k) as follows:

> The Boyd report is a differential study, which examines the impacts of two alternatives. That being the case the values used are not all inclusive of the total capital and operating costs required at the mine. The capital and operating costs that would in either of the cases studied have no impact on the calculation of the operating benefit, and were therefore not included in the values used in the Boyd study. Please see page 3-15 of the Boyd study for a definition of capital and operating costs. The values in EPGI's GTA constitute total mine capital and operating costs.

EPGI asserted ENMAX provided no explanation for its conclusion that the difference between the Boyd Report and the EPGI Application adversely impacted the present value of capital costs. EPGI stated that the purpose of the Boyd Report was to provide an estimate of the incremental operating benefits associated with the M8750; and those benefits reflecting the differences in operating costs between the Boyd Report Base Case and Notional Case A. EPGI was not applying for approval of the capital costs set out in the Boyd Report, therefore, ENMAX's statement was irrelevant.

EPGI submitted that ENMAX's fourth concern, that no assumption was made for increased productivity of replacement capital (technical advances) during the pit progression, would be *de minimis*. EPGI stated that the impact of incorporating technical advances into the Boyd Report for replacement equipment would be the same in both the Base Case and Notional Case A. In short, EPGI submitted that future technical advances might result in lower costs for both cases;

but there was no evidence to support the notion that cost differences would either widen or shrink.

Board Findings

The Board notes that the capital cost of the M8750 dragline has been reduced for rate base purposes and, therefore, the return on and return of capital for the disallowed amount which would normally have been included in revenue requirement has been excluded. The Board notes that, as a result of the exclusion, customers are in effect paying for a second, lesser-sized dragline which, could be considered to be equivalent to either of the draglines described in each of the notional cases. The Board considers that while the two scenarios are hypothetical, nonetheless, they represent reasonable substitutes for determining anticipated cost savings using different draglines as established in the Boyd Report.

The Board observes that the results of the Boyd Report show that benefits exist by using the M8750 dragline. The Board notes that the Report attempts to quantify those savings and that the quantum of the savings is dependent on both the coal production forecast for the year and the selection of the alternative to mine the coal.

The Board notes that the forecast annual coal production has increased since approving 2.9 mty in Decision E93094. The Board considers that using a revised forecast based on actual results is appropriate in these circumstances. The Board, therefore, for purposes of determining the dragline operating benefits, approves the forecast annual coal production of 3.5 mty.

The Board notes that the M8750 dragline is operating at the Genesee mine site. The Board also notes that the capital costs of the M8750 dragline were reduced before being included in rate base. The Board agrees that using the M8750 dragline produces benefits, through a reduced cost to coal mining operations, that are currently not included in the revenue requirement and therefore not in customer rates. The Board concludes that operating benefits exist through the use of the M8750 dragline at the Genesee mine. The Board considers that the quantum of those operating benefits must be determined.

(C) Value of the Operating Benefit

EPGI summarized the Boyd Report using a comparison of the life-time costs of the actual M8750 and M8200 dragline configuration (Base Case) and the hypothetical twin M8200 configuration (Notional Case A) with an annual coal burn of 3.5 million tonnes per year (mty). EPGI applied an 8% discount rate to the results to calculate a $27 million operating benefit by using the M8750 dragline. EPGI summarized the results as follows:

2. EPGI
(c) Cash Operating Expense

Annual coal burn of 3.5 mty	Base Case	Notional Case A	Difference (Savings)
Ongoing Operating Costs	537	625	(88)
NPV ($1995) with a real 8% discount rate	180	207	(27)
Initial and Ongoing Capital Costs	320	316	4
NPV ($1995) with a real 8% discount rate	196	168	28
Total Operating and Capital Costs	857	941	(84)
NPV ($1995) with a real 8% discount rate	376	375	1

Based on a coal burn of 3.5 million tonnes per year, which was the volume of coal actually used with both Genesee units running, the operating benefits associated with the M8750 dragline over a smaller M8200 dragline were approximately $27 million in 1995 dollars. The incremental capital costs associated with M8750 dragline versus the M8200 were approximately $28 million in 1995 dollars. Accordingly, the decision to select the M8750 dragline resulted in only a minimal additional cost to customers and EPGI submitted that the Decision should not have resulted in a disallowance.

EPGI stated the Boyd Report demonstrated that customers were enjoying the benefit of significantly lower coal costs of approximately $27 million, while paying only $8 million of the incremental capital cost calculated as the $28 million (as noted above) less EPGI's portion of the Board imposed disallowance of $20 million.

As part of EPGI's 1995 EEMA Settlement Agreement with interested parties, EPGI agreed that it would not pursue the matter of operating benefits associated with the selection of the M8750 dragline for 1995, 1996 and 1997. As a consequence of this agreement, EPGI stated it had absorbed $7.3 million of the estimated $27 million in operating benefits (both NPV in 1995 dollars).

For the purposes of the 1999/2000 GTA, EPGI included an amount of $2.84 million in recognition of the operating benefits arising from the operation of the M8750 dragline. This annual amount was based on an amortization of $19 million ($27 million less $7.3 million) in operating benefits over the remaining life of the plant applying a discount rate equal to EPGI's requested rate of return on rate base.

Position of the FIRM Customers

The FIRM Customers stated that EPGI proposed to increase the forecast fixed fuel cost by an amount of $2.84 million per year to recognize the "operating benefits" of EPGI's M8750 dragline. The FIRM Customers suggested EPGI's operating benefit was based upon a hypothetical analysis, conducted by the John T. Boyd Company, which concluded a $27 million

lifetime benefit existed as a result of the difference between the actual case and a hypothetical case employing two M8200 draglines

The FIRM Customers submitted that, by excluding the recovery of operating benefits for 1995, 1996 and 1997, EPGI was attempting to recover the remaining balance of $19 million through levelized payments. The FIRM Customers suggested the $2.84 million annual payment during the period 1999 to 2029 inclusive was equivalent to the penalty imposed by the Board for imprudence regarding the two issues of dragline sizing and timing of acquisition.[171]

The FIRM Customers described the payment as a "phantom cost" which would not be incurred by EPGI. The FIRM Customers suggested the annual payment represented approximately 10% of the actual fixed fuel costs and was proposed to be included in EPGI's revenue requirement, not only for the 1999/2000 test years, but for the remaining life of the plant.

In the previously negotiated settlements, the FIRM Customers stated the Consumers Group Cooperative had taken a consistent view that EPGI was not entitled to operating benefits of the nature claimed in this Application. The FIRM Customers submitted there was no factual or legal basis to support EPGI's proposal of recovering $2.84 million annually for non incurred costs.

Position of ENMAX

In Decision E93094, ENMAX noted the Board made a decision based on the best evidence at the time of the hearing to determine just and reasonable rates on a prospective basis. ENMAX stated this principle was generally accepted by rate making regulatory boards across North America. ENMAX summarized that the first dragline, the lower capacity M8200, went into operation in 1988[172] and the second unit, with greater capacity, the M8750, went into service in 1994. ENMAX submitted that EPGI chose to bring forward an after the fact analysis in an attempt to justify additional costs in its revenue requirement.

Unfortunately, ENMAX suggested, a similar tact of musing on the past was not carried out for any other of EPGI's assets, most notably the M8200. ENMAX submitted, as demonstrated in the Boyd Report,[173] and as acknowledged by its expert witness,[174] the utilization of the M8200, subsequent to the in-service date of the M8750, started at nil and eventually achieved 50% by the year 2010. ENMAX considered disbenefits were yielded by the smaller M8200 in the scenarios used in the Boyd report. ENMAX concluded that it appeared more prudent for EPGI to have started with the M8750 in 1988. However, ENMAX acknowledged the Board had the evidence before it, in a previous EEMA Decision, to allow the M8200 at the time. ENMAX recommended that the same principle should apply to the Board's decision with respect to the M8750 in decision E93094.

[171] Decision E97065
[172] Tr. p.312; ENMAX-EPGI.35
[173] Table 4.2
[174] Tr. p. 880

ENMAX stated that EPGI's proposal to add $2.84 million to the fixed fuel costs for each of 1999 and 2000 was derived from spreading evenly the present value of a differential in operating costs between two alternatives over a period of 36 years. ENMAX indicated that only two of those 36 years pertained to the current application and, thereafter, EPGI would have to make its pitch through the PPA process.

ENMAX stated the future actual annual savings, if any, could be very different from that yielded in the present value of annuity calculation provided by EPGI. ENMAX calculated that, based on the Boyd report, the operating cost differentials were $1.655 million and $1.669 million in 1999 and 2000, respectively. ENMAX concluded that, even if one were to accept the savings alleged by EPGI, a net mismatch of $2.4 million would still exist over the test period.

ENMAX recommended that EPGI's requested operating benefit of $2.84 million per year should be disallowed.

Position of EPGI

EPGI indicated that ENMAX suggested the operating benefits, associated with the M8750, should be recovered based on the year-by-year values shown in the Boyd Report rather than on a levelized basis over the life of the dragline. EPGI refuted ENMAX's claim that the calculated operating cost differentials were only $1.655 million and $1.669 million in 1999 and 2000, respectively and that the savings would result in a net mismatch of $2.4 million over the test period.

EPGI calculated the discount rate used to develop the $2.84 million as 10.58%, being the average of the 10.57% and 10.59% EPGI rates of return on rate base for 1999 and 2000 respectively.[175] EPGI assured that customers would be indifferent to levelizing the operating benefits because the time-wise advancement of future operating benefits was subject to annual discounting at 10.58%. EPGI submitted that the Board should levelize the operating benefits over the life of the M8750 in the amount of $2.84 million.

Board Findings

The Board, having established the jurisdiction and concluded that operating benefits exist, must establish a quantum of the benefits. The Board notes that EPGI has requested an amount of $2.84 million annually from 1999 to 2029 inclusive as a levelized payment for those benefits. The Board also notes that ENMAX has submitted that, if operating benefits were determined to exist, then the operating cost differentials should be $1.6 million and $1.7 million for 1999 and 2000 respectively.

[175] EPGI Application, p.25

The Board considers that an approach consistent with the normal revenue requirement determination is a reasonable way to ascertain a value for the dragline operating benefits. Therefore, the Board will use the values, as shown in the Report, to determine the benefit. The Board notes that Table 5.3 indicates the mine operating costs for the coal burn of 3.5 mty using Notional Case A are calculated as $14.818 million and $15.017 million for 1999 and 2000 respectively. For the same years, Table 4.3 shows similar costs for the Base Case as $13.163 million and $13.348 million.

The Board considers that the difference between the Notional Case A and the Base Case represents a fair and reasonable amount as a surrogate for determining the savings derived from the M8750 dragline.

The Board also considers that using an annual forecast of mining costs eliminates any question as to:

- intergenerational equity,
- the use of a discount factor which changes as the financial markets change,
- the possible future change in burn rate, and
- the inclusion of savings beyond 2020.

The Board also considers that using the forecast amounts for each of the years satisfies the position of LE/RD that 1998 benefits should not be included in the levelized annual calculation.

Accordingly and for purposes of this Decision, the Board directs EPGI, in its refiling, to include a dragline operating benefit of $1.6 million for 1999 and $1.7 million for 2000. The amounts should be clearly shown as a cost of coal in the refiling.

(2) Fixed Fuel Cost

EPGI forecast the total fixed fuel costs for 1999 and 2000, including adjustments and start-up fuel, to be $29.0 and $30.4 million respectively as summarized in the tables below. The fixed fuel costs for the Genesee units included an adjustment to recognize the operating benefits achieved by the Marion 8750 dragline described in greater detail in section 2(c)(1).

2. EPGI
(c) Cash Operating Expense

EPGI FIXED FUEL COSTS
(as filed) ($ millions)

	Genesee		Clover Bar				Rossdale			Total
	G1	G2	CB1	CB2	CB3	CB4	RD8	RD9	RD10	
Fuel before dragline disallowance	11.2	11.2								
FCL Dragline Disallowance	(1.4)	(1.4)								
Fixed Fuel	9.8	9.8	1.1	1.2	1.1	1.1	0.6	0.6	0.6	25.8
Dragline Operating Benefit	1.4	1.4								2.8
Start-up Fuel	0.1	0.1	0.1	-	0.1	-	0.1	-	-	0.5
Total	11.3	11.3	1.2	1.2	1.1	1.1	0.7	0.6	0.6	29.0

EPGI FIXED FUEL COSTS
(as filed) ($ millions)

	Genesee		Clover Bar				Rossdale			Total
	G1	G2	CB1	CB2	CB3	CB4	RD8	RD9	RD10	
Fuel before dragline disallowance	11.9	11.9								
FCL Dragline Disallowance	(1.5)	(1.4)								
Fixed Fuel	10.5	10.5	1.1	1.2	1.1	1.1	0.6	0.6	0.6	27.2
Dragline Operating Benefit	1.4	1.4								2.8
Start-up Fuel	0.1	0.1	0.1	-	0.1	-	0.1	-	-	0.5
Total	11.9	11.9	1.2	1.2	1.2	1.1	0.7	0.6	0.6	30.4

EPGI responded to questions, during the hearing, respecting the variance between 1999 and 2000 forecast fixed fuel costs shown above. EPGI indicated that the increase in 2000 was due to the fixed coal cost portion related to inflation and the impact of capital replacements and additions on depreciation. EPGI noted that a number of critical replacements would occur in 1999 due to the mine equipment fleet having reached 11 years of age. As well, EPGI explained both draglines would reach major maintenance milestones of 35,000 hours with the full impact of the capital replacements to occur during 2000.

Intervenors did not bring forward any issues respecting fixed fuel costs other than fixed coal costs and the Dragline Operating Benefits .

Board Findings

The Board will deal with concerns respecting fixed coal costs in the following section dealing with variable fuel costs. The Board has reviewed the remaining fixed fuel costs and has found the explanations provided for increases to the annual costs to be reasonable. Accordingly, the Board approves the annual costs shown in the tables below which includes an adjustment for the Genesee dragline operating benefit.

EPGI FIXED FUEL COSTS
Board Approved 1999 ($ millions)

	Genesee		Clover Bar				Rossdale			Total
	G1	G2	CB1	CB2	CB3	CB4	RD8	RD9	RD10	
Fuel before dragline disallowance	11.2	11.2								
Dragline Disallowance	(1.4)	(1.4)								
Fixed Fuel	9.8	9.8	1.1	1.2	1.1	1.1	0.6	0.6	0.6	25.8
Dragline Operating Benefit	.8	.8								1.6
Start-up Fuel	0.1	0.1	0.1	-	0.1	-	0.1	-	-	0.5
Total	10.7	10.7	1.2	1.2	1.1	1.1	0.7	0.6	0.6	27.9

EPGI FIXED FUEL COSTS
Board Approved 2000 ($ millions)

	Genesee		Clover Bar				Rossdale			Total
	G1	G2	CB1	CB2	CB3	CB4	RD8	RD9	RD10	
Fuel before dragline disallowance	11.9	11.9								
Dragline Disallowance	(1.5)	(1.4)								
Fixed Fuel	10.5	10.5	1.1	1.2	1.1	1.1	0.6	0.6	0.6	27.2
Dragline Operating Benefit	.8	.9								1.7
Start-up Fuel	0.1	0.1	0.1	-	0.1	-	0.1	-	-	0.5
Total	11.4	11.5	1.2	1.2	1.2	1.1	0.7	0.6	0.6	29.4

(3) Variable Fuel Cost

(A) Coal Costs

EPGI's variable and fixed coal costs, associated with the Fording Coal Limited (FCL) agreement, were summarized as follows, in the table below:

	1996 Refiling	1996 Actual	1997 Actual	1998 Reforecast	1999 Forecast	2000 Forecast
Generation (MWh)	6,064	6,328	6,253	6,278	6,035	6,112
Variable Coal Cost ($/MWh)	2.27	2.16	2.25	2.23	2.34	2.48
Fixed Coal Cost ($/MWh)	3.40	3.27	3.12	3.11	3.58	3.75
Total Coal Cost ($/MWh)	5.66	5.42	5.36	5.34	5.92	6.23
Tonnes burned (000)	3,465	3,573	3,514	3,541	3,383	3,427
Variable Coal Cost ($/tonne)	3.98	3.83	4.01	3.95	4.17	4.44
Fixed Coal Cost ($/tonne)	5.95	5.79	5.55	5.51	6.38	6.68
Total Coal Cost ($/tonne)	9.93	9.62	9.56	9.46	10.55	11.12
Strip ratio		6.6	6.1	6.4	6.1	7.2

Source: FIRMD-EPGI.28 and Exhibit 47, Tr. p.1045-1046

EPGI forecast the unit variable coal cost to be $2.34/MWh in 1999 which was approximately $0.11/MWh higher than the 1998 reforecast and $0.07/MWh higher than the 1996 GTA Refiling. EPGI forecast the unit variable coal cost to increase $0.14/MWh to $2.48/MWh in the year 2000.

EPGI explained the actual unit variable coal cost had been relatively stable from 1996 through 1998, with the exception of 1996 when the actual unit variable coal cost was lower than forecast due to unexpected decreases in equipment operating costs. EPGI explained the majority of the decrease was only temporary as a result of unexpected warranty work and noted that equipment operating costs had returned to normal levels in 1997 and 1998.

EPGI's unit variable coal cost increased in 1999 and 2000 primarily due to inflation and higher strip ratios as mining advances to the south. The strip ratio referred to the volume of waste material (topsoil, subsoil, overburden and interburden) divided by the amount of coal recovered. EPGI forecasted the overburden, which varies from year to year, to gradually increase over the life of the mine.

The Intervenors submitted that there was a lack of information from EPGI on the joint venture agreement with FCL in respect of the individual components that comprise the total coal costs.

The Intervenors recommended, due to an inadequate testing of the costs, that coal costs should be reduced to a per unit level comparable to previous years.

The Intervenors raised two issues with respect to the variable coal costs. The first issue concerned the lack of information on the agreement between EPGI and FCL and the second issue was the component increases of the variable costs between 1998, 1999 and 2000.

(i) The Agreement between EPGI and Fording Coal Limited

Position of the FIRM Customers

The FIRM Customers noted that EPGI's joint venture agreements with FCL governed the costs charged to EPGI and the sharing of profits from the joint venture. The FIRM Customers stated a confidential budgeting process between the joint venture partners established the costs EPGI proposed to collect from customers.[176]

The FIRM Customers considered that this arrangement was not a normal customer–supplier relationship. The FIRM Customers suggested that, while most of EPGI's forecasts may be reviewed for their reasonableness, the same could not be said of the FCL related costs. In particular, the FIRM Customers noted these agreements were different in two respects. First, costs could not be properly tested due to confidentiality provisions in the agreements, and second, EPGI stood to gain direct financial benefits from overstated forecasts and budgets and any productivity or cost improvements.

The FIRM Customers submitted EPGI's and FCL's current process was inherently flawed. Given EPGI stood to gain from over-estimated FCL costs, the FIRM Customers suggested the forecasts must be viewed with considerable skepticism and suspicion. The FIRM Customers submitted such suspicions were warranted and cited that, over the past three years, EPGI over-forecast mining contract costs by about $2.1 million per year as shown below:

	1996	1997	1998 Reforecast	Average
Total Forecast Cost (Per SPPA-EPGI.08)	36.9	35.4	35.4	35.9
Variable Coal Cost ($ million)	13.7	14.1	14.0	13.9
Fixed Coal Cost ($ million)	20.7	19.5	19.5	19.9
Total Actual Cost (Per FIRMD-EPGI.28)	34.3	33.5	33.5	33.8
Forecast over/(under) Actual	2.6	1.9	1.9	2.1

[176] SPPA-EPGI-3

Because of the questionable nature of these forecasts, the FIRM Customers recommended a reduction to the total allowable mine related costs (fixed and variable) by $2.1 million in both 1999 and 2000 to reflect EPGI's trend towards overstated forecasts.

Position of IPPSA/SPPA

IPPSA/SPPA contended that the Edmonton Power/Fording Coal Limited Agreement remained shrouded in mystery. IPPSA/SPPA concluded that, according to EPGI, there were five contracts in place which were not linked to each other. The first three agreements set out the establishment of the Joint Venture, the dedication and unitization of the coal for Genesee and the construction agreement. IPPSA/SPPA suggested these historical agreements were of little interest in this proceeding.

IPPSA/SPPA indicated the other two agreements were of more interest:

1. The Operating Agreement which included rules and arrangements establishing FCL as the operator of the Genesee Coal Mine.
2. The Purchase and Sale Agreement which details the financial/commercial terms by which EPI (EPGI) will purchase coal from the operator.

IPPSA/SPPA stated that, throughout the proceeding, EPGI refused to provide details on these agreements in order for consumers to test the validity of the costs and cost increases for which EPGI had applied. IPPSA/SPPA stated that EPGI's standard response was:

> The terms of the Agreement with FCL are subject to a confidentiality provision in the Agreement. EPGI has made inquiries with FCL respecting the potential release of information and FCL has indicated that it will not allow the information to be released.

IPPSA/SPPA added that EPGI went on to state:

> Further, release of the requested information would prejudice consumers of electricity generated in Alberta. The disclosure of the commercial terms between mine operators and generator would likely result in an increase in the average coal costs for Alberta electricity consumers.

IPPSA/SPPA stated that when questioned further, EPGI claimed that due to the competitive nature of the coal business in Alberta the "coal contractors wish to hold their contractual terms and conditions and pricing and whatnot" to themselves.

IPPSA/SPPA noted EPGI also informed the Board that the only mechanism available for FCL to be displaced (i.e. the JV Agreements terminated) was for FCL to be in breach of an Agreement. Regardless of the resulting price charged by FCL, EPGI had no means to get a different coal

operator. IPPSA/SPPA submitted that the confidentiality provisions for the Genesee mine operator were not in place to protect FCL from competition, they were put in place to protect consumers from properly testing the prudence and validity of the prices charged.

IPPSA/SPPA noted EPGI described the process by which coal prices were determined for Genesee. IPPSA/SPPA restated that FCL submitted, to EPGI, a detailed mine budget which was reviewed by EPGI. IPPSA/SPPA indicated that EPGI claimed the resulting negotiations were "almost as bad as a hearing" with EPGI fighting on behalf of consumers to drive coal costs down. IPPSA/SPPA queried how well the consumers' interests were served by these secret negotiations and whether the interests of customers were really paramount in EPGI's mind when these negotiations took place.

IPPSA/SPPA stated that one aspect of the detailed mine budget was the variable operating cost resulting from the negotiations and for which EPGI was seeking Board approval. IPPSA/SPPA learned that "the mine operator has incentives to reduce costs and EPGI does share in the reduced costs." IPPSA/SPPA queried the motivation of EPGI to reduce operating costs when, if the costs were forecast to be high, EPGI's shareholders would reap the benefit.

IPPSA/SPPA noted, from Exhibit 46, the response to SPPA-EPGI.08, that the actual cost was below budget only one year in the last three (1996 to 1998 data). IPPSA/SPPA suggested that, while customers should be able to take comfort from the historical data, little comfort was available. IPPSA/SPPA indicated their lack of comfort resulted from the fact that the 1999 and 2000 budget forecasts were unlikely to be revealed, ever, due to the proposed industry restructuring. Considering the significant cost increases applied for, IPPSA/SPPA expressed concern that the budgeting mechanisms in place did not provide proper incentives for EPGI to minimize coal costs.

IPPSA/SPPA submitted that, upon closer examination, the accuracy of the "budgeting process" came into question because, as shown in EPGI-FIRMD-28, EPGI had consistently over-budgeted by about $2 million during the past three years as shown in the table below under column D:

2. EPGI
(c) Cash Operating Expense

		Total Cost ($ million) B	Total Budget ($ million) C	Budget Variance ($ million) D	Budget Variance (%) E	Actual Over Budget (%) F	Actual Over Budget ($ million) G
1	1996 Actual	34.3	36.9	(2.6)	(7.0)	0.7	0.3
2	1997 Actual	33.5	35.4	(1.9)	(5.4)	3.0	1.1
3	1998 Reforecast	33.5	35.4	(1.9)	(5.4)	(1.3)	(0.5)

Source:
- **B** FIRMD-EPGI.28
- **C** Exhibit 46, SPPA-EPGI.08(e)
- **D** C minus B
- **E** D / C
- **F** Exhibit 46, SPPA-EPGI.08(f)
- **G** F x C

IPPSA/SPPA submitted the conflicting data on the record (column E compared to column F) further destroyed any credibility EPGI had in defending the budgeting process with its joint venture partner.

IPPSA/SPPA stated that in order for EPGI to test the reasonableness of the operating costs, EPGI had retained an anonymous Alberta based consulting company to develop indexes which were used by EPGI in their negotiations with FCL in setting the annual mine budget. IPPSA/SPPA indicated that the effective performance of FCL was measured by EPGI through periodic testing by another consultant in a benchmarking study.

IPPSA/SPPA noted a benchmarking study had not been not performed for 1998 as EPGI felt, that since "the early conclusions" from the 1997 study were that "the costs came in lower than the industry", the cost of a study for 1998 was not justified. IPPSA/SPPA submitted that the relative performance of the Genesee mine versus other mines was of no consequence and did not give EPGI the right to consistently over-budget and over-charge customers.

IPPSA/SPPA noted that a second aspect of coal related costs were those deemed to be fixed. EPGI owned the capital assets on a 50/50 basis with FCL. IPPSA/SPPA noted EPGI recovered its fixed related costs, such as return and depreciation, as approved by the Board. IPPSA/SPPA stated that FCL fixed costs, however, were determined by some secret formula. IPPSA/SPPA stated there did not appear to be any mechanism for consumers to test the reasonableness of the FCL fixed costs claimed by EPGI.

Again, IPPSA/SPPA queried if the proper mechanisms were in place to control costs. IPPSA/SPPA suggested that while the detailed mine budget set out the forecast capital cost additions, both EPGI and FCL could increase earnings by over forecasting capital addition

requirements. IPPSA/SPPA noted that, for FCL capital (fixed) costs, EPGI took the role of a regulator in determining if the costs were reasonable which, IPPSA/SPPA submitted, did not result in a high comfort level regarding the prudence of these costs. Overall, IPPSA/SPPA noted that EPGI forecast coal costs to increase during 1999 and 2000.

While the Board accepted the approach adopted by EPGI in forecasting coal costs in the past, IPPSA/SPPA submitted that the 1999/2000 Application was fundamentally different. IPPSA/SPPA suggested that if industry restructuring unfolded according to the intent of Bill 27, there would be no future opportunities for the Board or customers to review these forecasts. IPPSA/SPPA noted that in the past, if a utility was overly aggressive in their forecasts, the Board had the opportunity to reflect this aggression in future Decisions. IPPSA/SPPA submitted that, the control mechanism on EPGI's 1999/2000 coal cost forecasts was lost.

IPPSA/SPPA submitted that, due to the nature of the Agreements between EPGI and FCL, the cost forecasts applied for could not be properly tested. IPPSA/SPPA submitted the Board should be cognizant of this condition when reviewing specific requests by consumers to have the forecast amounts adjusted downward.

Given the financial incentive for EPGI to over-forecast its joint venture mining costs, IPPSA/SPPA recommended a reduction to the Total Mine Operating Cost to a level consistent with historical operation. IPPSA/SPPA submitted the average unit coal cost, per unit of output, was $5.71/MWh from 1996 to 1998. IPPSA/SPPA recommended that in order to maintain the unit output cost of $5.71/MWh for 1999 and 2000, the Total Mine Budget should be reduced by $1.2 million and $3.2 million respectively.

Position of EPGI

EPGI stated the FIRM Customers recommended that the Board should reduce the total allowable mine related costs by an alleged amount of $2.1 million in both 1999 and 2000. EPGI also stated that IPPSA/SPPA recommended a reduction to coal costs of $1.2 million and $3.2 million respectively for 1999 and 2000. EPGI considered that the FIRM Customers' claim that EPGI's forecast should be viewed with "considerable skepticism and suspicion" given that "EPGI stands to gain from overestimating FCL costs" was erroneous.

EPGI asserted the historical comparison suggested by the Intervenors was flawed. The FIRM Customers and IPPSA/SPPA were incorrect in their assertions that EPGI's coal costs have historically been higher than forecast. EPGI stated the evidence demonstrated that EPGI did not over-forecast coal costs, but rather, to the contrary, EPGI's actual coal costs were higher than forecast.

EPGI stated that Intervenor's calculations, in the summaries each provided, were incorrect as the forecast and actual costs used by these parties were not comparable. EPGI explained that, as shown in Schedule G-2 of the Application, the total fixed fuel costs reflected the dragline

disallowance of $2.9 million in each of the years 1996 through 2000. As well, actual costs that were reported in FIRMD-EPGI-28 reflected the $2.9 million disallowance.

EPGI and interested parties agreed to the treatment of the FCL portion of the dragline disallowance as set out in EPGI's letter to the Board dated 10 March 1997 in respect of the 1995 EEMA Adjustment negotiated settlement agreement. In that letter, EPGI advised the Board that parties had agreed that the total $15.46 million disallowance was to be amortized over a period of 7.2 years, with the amortized amount of $2.9 million being deducted from EPGI's fixed fuel cost from 1996 onward.

In response to SPPA-EPGI-08(e), EPGI provided the total budget amounts set for the Joint Venture and set out the payments required by FCL for mine costs. As the dragline disallowance was only attributable to EPGI, the FCL costs did not include the disallowance. Accordingly, to compare the costs in SPPA-EPGI-08(e) to the total costs in FIRMD-EPGI-28, EPGI stated the disallowance must be deducted from the forecast figures in the respective Intervenor tables. EPGI indicated the correct analysis was shown as follows:

	($ million)			
	Actual 1996	**Actual 1997**	**Refiling 1998**	**Average**
Total Budget SPPA-EPGI.08	36.9	35.4	35.4	35.9
Total Dragline Disallowance SCH G-2U	(2.9)	(2.9)	(2.9)	(2.9)
Total Comparable Budget	34.0	32.5	32.5	33.0
Total Actual FIRMD-EPGI.28	34.3	33.5	33.5	33.8
Total Coal Cost Over Budget	0.3	1.0	1.0	0.8

EPGI asserted the table indicated that EPGI's costs from 1996 to 1998 actually averaged $0.8 million over budget. EPGI submitted there was no basis for the suggested reduction in EPGI's forecast coal costs for 1999 and 2000. Instead, EPGI noted the record demonstrated that EPGI had incentives to reduce coal costs, that EPGI negotiated coal costs on a yearly basis that were as low as possible and that EPGI's historical forecasts did not overstate actual coal costs.

EPGI noted that IPPSA/SPPA asserted that the confidentiality provisions for the Genesee mine operator were put in place "to protect consumers from properly testing the prudence and validity of the prices charged" by FCL to EPGI under the purchase and sale. Notwithstanding the testimony that EPGI negotiated with FCL in the annual mine operations budgeting exercise to drive costs down, IPPSA/SPPA questioned whether the interests of customers were paramount during the negotiations.

EPGI also noted IPPSA/SPPA's assertion that there were incentives for FCL to reduce variable operating costs and, because EPGI shared in those incentives, EPGI was somehow biased toward over-forecasting mine costs.

EPGI observed IPPSA/SPPA's reference to the differences between forecast and actual costs from 1996 to 1999, as well as to the applied-for cost increases in 1999 and 2000, as support for their claim that the budgeting mechanisms in place did not provide proper incentives for EPGI to minimize coal costs. EPGI directed IPPSA/SPPA to the evidence that independent mining consultants confirmed the reasonableness of Genesee mine operating costs vis-à-vis other mines, despite IPPSA/SPPA's claim that the relative performance of the Genesee mine to other mines was "of no consequence".

EPGI asserted that both EPGI and FCL had an incentive to minimize coal costs to maintain the position of the Genesee Units in the provincial stacking order. EPGI reiterated that should costs increase, EPGI risked losing its place in the stacking order, which would potentially result in lost revenues for both EPGI and FCL.

Board Findings

The Board notes that past decisions have been based on data and information similar to the current Application. The Board accepts the explanation by EPGI that the actual results, on average 2.4 % over forecast, are within a reasonable percentage of the forecast, when adjustments are made to compare similarly determined numbers.

The Board notes IPPSA/SPPA's concern as to how well consumer interests are served by EPGI and FCL using private negotiations to set a coal price for EPGI. The Board also notes IPPSA/SPPA's concern with respect to the budgeting mechanism in place to ensure the proper incentives to minimize coal costs. The Board notes EPGI's explanation that an independent consulting company develops indices for negotiating with FCL, and that another consulting company provides bench-marking studies for measuring other provincial coal costs against the Genesee mine costs. The Board considers that the independent consulting report would be of more benefit if it were available to all parties. The Board considers that a long-term incentive exists for both EPGI and FCL to minimize coal costs, thereby stabilizing the position of the Genesee units in the provincial stacking order and maintaining the forecast revenue stream.

The Board notes that the concern of IPPSA/SPPA with respect to industry restructuring and the lack of future opportunities for the Board to review the forecasts has already been addressed by government legislation, including the IAT process which is itself subject to Board approval. The Board considers that the PPA process will ensure that the allowed coal costs provide an appropriate balance between customer and owner interests.

(ii) Variable Coal Costs

Position of the FIRM Customers

The FIRM Customers noted that EPGI forecast significant increases in both the variable and fixed costs of coal and referred to the table, shown earlier in this section, depicting the impact on a dollar per tonne burned basis. The FIRM Customers concluded the per unit of energy produced costs for Genesee also appeared to be rising.

The FIRM Customers stated, according to EPGI, the increase in variable costs was due to changes in strip ratios, inflation and other undetermined costs. The FIRM Customers summarized the impact as follows:

	1998	1999	2000	Source
Unit Cost ($/t)	$3.95	$4.17	$4.44	FIRMD.EPGI-28
Year-Year Unit Cost Change ($/t)		0.21	0.27	Yearly Change
Year-Year Unit Cost Change (%)		5.4	6.4	Line 2/1
Strip Ratio Relative Impact ($/t)	0.02	(0.02)	0.07	X47 at T1045
Year-Year Strip Ratio Change		(0.04)	0.09	Yearly Change
Strip Ratio Impact		(1.0%)	2.0%	Line 5/1

The FIRM Customers considered that when inflation was taken into account, it appeared a portion of the cost increase was due to changes in "Royalties and Other" as shown below:

	1998 to 1999	1999 to 2000	Source
Strip Ratio	(1.0%)	2.0%	Table Above
Inflation	2.2%	2.1%	SPPA.EPGI-03(h)
Royalties and Other	4.2%	2.3%	Line 4-1-2
Variable Cost Increase	5.4%	6.4%	FIRMD.EPGI-28

The FIRM Customers submitted that, in response to requests for further information on the "Other" factors, EPGI stated "1.3% is due to the change in the burn forecast."[177] However, the FIRM Customers noted the changes in the burn forecast (volume of coal mined and burned) were

[177] Exhibit 47, Tr. p.1045

already captured in the ratio of $/tonne burned basis, therefore, the FIRM Customers contended subtracting this percentage change was an error, as the impact of volume of coal burned had been accounted for in the ratio.

The FIRM Customers submitted that, despite several requests for further detail, EPGI was unable, or unwilling, to provide any further information indicating how "Royalties and Other" factors accounted for the 4.2% and 2.3% increases between 1998 and 2000. Since EPGI declined to provide any detailed information on royalties (or other costs related to the joint venture agreements), these cost increases could not be properly tested nor supported. Again, the FIRM Customers noted that the agreements between EPGI and FCL precluded a proper review.

Since they considered these costs could not be adequately tested based on the evidence in these proceedings, the FIRM Customers submitted it would be inappropriate for the Board to approve the variable cost increases as filed. The FIRM Customers submitted the "Royalties and Other" variable cost increases of 4.2% in 1999 and 2.3% in 2000 were excessive and should not be allowed, and therefore, recommended the variable mine related costs be reduced by those percentages, or by $0.6 million in 1999 and $0.4 million in 2000.

Position of EPGI

EPGI noted that Intervenors questioned the increase in variable coal costs in 1999 compared to previous years, and from 1999 to 2000. EPGI responded that changes in variable coal costs per tonne burned were attributable to inflation and higher strip ratios as explained in the Application. In response to an undertaking, Exhibit 57, Tr. p.1573, EPGI provided the following detailed breakdown of the 5.6% and 6.5% increases for 1999 and 2000:

Item	Portion of 5.6 % increase in forecast variable coal costs from 1998 to 1999 (%)	Portion of 6.5 % increase in forecast variable coal costs from 1999 to 2000 (%)
Change in coal burn forecast	4.5	(1.3)
Inflation	2.7	2.5
Increased royalties	0.0	2.6
Change in strip ratios	(1.6)	2.2
Other factors (e.g. increased haul distance)	0.0	0.5
Total increase	5.6	6.5

Source: Exhibit 57, Tr. p. 1573

EPGI explained the variable coal costs increased from $3.95/tonne in 1998 to $4.17/tonne in 1999 for a change of 5.6 % and to $4.44/tonne in 2000 for a change of 6.5%. EPGI explained the change in 1999 and 2000 was primarily due to inflation and higher strip ratios as mining

advanced to the south. EPGI indicated a detailed analysis of changes in strip ratios from 1996 to 2000 and the effect on variable coal costs was provided in Exhibit 47.

EPGI noted the FIRM Customers' argument that the forecast increases of 4.2% and 2.3% in the "royalties and other" category for 1999 and 2000 were "excessive" and could not "be adequately tested". EPGI also noted the FIRM Customers suggestion for a reduction in variable coal costs of $0.6 million in 1999 and $0.4 million in 2000.

EPGI submitted, however, that the record did not support the FIRM group's assertion that the royalties and other cost category were "excessive." Similarly, EPGI stated there was no basis for arguing that the costs could not be adequately tested. EPGI submitted the evidence on the record explained and demonstrated the reasonableness of EPGI's variable coal costs, including the royalties and other category.

EPGI noted the FIRM Customers claimed that EPGI incorrectly included forecast changes in EPGI's burn forecast as an explanation of the increase in the "royalties and other" category. EPGI acknowledged that the FIRM Customers were correct in that changes in the burn forecast were already captured in the ratio of $/tonne burned basis, and therefore EPGI would exclude these changes in its variance analysis.

EPGI explained that the royalty increase was due to an increase in both freehold and Crown royalty rates. The increase in freehold royalty rates took place from time to time pursuant to the provisions of the Agreement signed with FCL in 1980. EPGI explained that the calculation of the freehold royalty rate was a component of the joint venture agreement with FCL and had been entered into in the late 1970s.[178] Although the freehold rate was related to the Crown royalty rate, EPGI stated it was not a one-for-one relationship.

EPGI stated the increase in Crown royalty rate was due to an assumed rate of $0.61 per Crown tonne mined. EPGI compared this rate to 1999 and years previous, going back to 1993, at $0.55 per tonne mined. EPGI based the forecast increase in 2000 on the expected change in the Sub-bituminous Crown Royalty rate structure, which was expected to be implemented by the Alberta Department of Resource Development.

EPGI asserted the FIRM Customers' calculation of percentage increases was incorrect as the calculation only reflected escalation by EPGI's estimate of the Alberta CPI. EPGI indicated SPPA-EPGI-03(f) demonstrated that coal prices were escalated each year using both the Alberta CPI and an Alberta Labour index. In part (h) of the same response, EPGI provided the rates used to escalate coal costs in 1999 and 2000. EPGI provided the weighted average escalation rate, taking into account the appropriate proportions attributable to both labour costs and equipment operating and maintenance costs, in the undertaking filed as Exhibit 57. EPGI calculated the rates to be 2.5% and 2.7% for 1999 and 2000, respectively. Using these escalation factors, the

[178] Tr. p.1571

FIRM Customers' calculation of changes due to strip ratios, and correcting for EPGI's previous treatment of the burn forecast, EPGI revised the FIRM Customers' figures as follows:

	1998 to 1999	1999 to 2000	Source
Strip Ratio	(1.0 %)	2.0 %	Table Above
Inflation	2.5 %	2.7 %	SPPA.EPGI-03(h)
Royalties and Other	3.9 %	1.7 %	Line 4-1-2
Variable Cost Increase	5.4 %	6.4 %	FIRMD.EPGI-28

EPGI explained, in Exhibit 57, that the 3.9 % increase in 1999 over 1998 in the royalties and other category was not a function of royalties, but was due to such factors as increased haul distances, lower diesel fuel prices in 1998 and other factors. EPGI also explained that the 1.7 % increase in 2000 over 1999 was primarily related to increases in Crown and freehold royalties, as explained earlier.

EPGI submitted that the annual changes in the royalties and other category were explained since the evidence demonstrated that there were valid reasons for the increases. EPGI submitted that it provided explanations of the forecast increases in variable coal costs, demonstrated that the increases were reasonable and justified, and should be approved by the Board.

Board Findings

The Board notes that the strip ratios for 1999 and 2000 are calculated to be 6.1 and 7.2 respectively. The Board considers the impact of the strip ratio on the unit variable cost of coal is mainly a function of the type and volume of waste that is being handled, although it does include the impacts of other factors. The Board accepts EPGI's explanation that as mining advances to the south, deeper overburden areas that require removal are encountered. The Board also notes that Intervenors did not raise any objections to the strip ratios. The Board has reviewed the impact of the strip ratios on the unit variable coal cost and considers the strip ratios for 1999 and 2000 to be reasonable.

The Board notes the FIRM Customers' contention that the impact of volume of coal burned had been accounted for and the acknowledgement from EPGI that the FIRM Customers' disagreement was correct with respect to the change in the burn forecast.

The Board agrees that the increase in the Royalties and Other category between 1998 and 1999 appears to be more than expected, whether using 4.2% as calculated by the FIRM Customers or 3.9% as revised by EPGI. The Board considers that EPGI has not provided an adequate explanation to warrant the full increase and therefore allows 2/3 of the increase, thereby, reducing Royalties and Other category by $0.2 million in each of 1999 and 2000. The Board

directs EPGI, in its refiling, to reduce Royalties and Other by $0.2 million in each of 1999 and 2000.

However, the Board considers the increase for Royalties and Other to be reasonable between 1999 and 2000. The Board accepts EPGI's explanation that the forecast Crown royalty rate is expected to increase from $0.55 to $0.61 per Crown tonne mined. The Board therefore makes no further adjustment to the year 2000 variable coal cost.

(B) Variable Natural Gas Costs

EPGI provided a forecast of variable fuel costs for its natural gas fired plants as follows:

Plant	1999	2000
Clover Bar	$78.6 million	$66.4 million
Rossdale	$23.7 million	$13.1 million
Total	$102.3 million	$79.5 million

Source: Schedule G-2-U

The volume of natural gas burned depends on the economic dispatch of the natural gas fired units and can vary considerably from year to year.

EPGI's forecast of the unit price for natural gas during the test years was provided in Appendix F Table 14 to EPGI's Application EPGI explained that the forecast price was based on the NYMEX futures price with an adjustment for the basis differential back to AECO 'C' in Alberta. EPGI added a burner tip adjustment to the forecast natural gas price at AECO 'C'. EPGI noted that they were forecasting an eight cent reduction in the burner tip adjustment due to changes to transportation rates in the recent Northwestern Utilities Limited negotiated settlement.

Board Findings

The Board notes that no issues were raised respecting EPGI's forecast of the price or the volume of natural gas for the test years. The Board has reviewed EPGI's price and volume forecasts for the test years and finds them to be reasonable.

(4) Operating and Maintenance

EPGI's forecast costs reflected fixed cost projections derived from EPGI's budget for 1999 and 2000. EPGI's budgeting process began in August 1998, leading to a budget for 1999 and 2000 approved by the EPCOR Board of Directors on October 26, 1998. In developing its budget, EPGI used a "bottom up" approach to forecasting expenditures based on the best available information for expected work activity and cost levels during the forecast period.

2. EPGI
(c) Cash Operating Expense

EPGI provided tables of the operations and maintenance expenses by unit for each of 1999 and 2000 that have been combined onto one table as follows:

1999
OPERATIONS AND MAINTENANCE
($ millions)

	Genesee		Clover Bar				Rossdale			Total
	G1	G2	CB1	CB2	CB3	CB4	RD8	RD9	RD10	
Fixed and Variable	4.5	4.5	1.5	1.5	1.5	1.5	1.1	1.1	1.1	18.3
Less: Variable	1.3	1.4	0.1	0.1	0.1	0.2			0.1	3.3
Fixed Production	3.2	3.1	1.4	1.4	1.4	1.3	1.1	1.1	1.0	15.0
Maintenance and repairs	6.7	6.7	2.3	2.3	2.3	2.3	1.0	1.0	1.0	25.6
Purchase site power and standby	1.5	1.5		0.1	0.1		0.1	0.1	0.1	3.4
Generation Admin	2.5	2.5	0.7	0.6	0.6	0.7	0.5	0.5	0.5	9.1
Production O and M	13.9	13.8	4.4	4.4	4.4	4.3	2.7	2.7	2.6	53.1
Corporate Services	2.6	2.6	0.7	0.7	0.7	0.7	0.5	0.5	0.5	9.5
Generation Pool Access	2.4	2.3	0.9	0.9	0.9	0.9	0.4	0.4	0.4	9.5
Total	18.9	18.7	6.0	6.0	6.0	5.9	3.6	3.6	3.5	72.1

2. EPGI
(c) Cash Operating Expense

2000
OPERATIONS AND MAINTENANCE
($ millions)

	Genesee		Clover Bar				Rossdale			Total
	G1	G2	CB1	CB2	CB3	CB4	RD8	RD9	RD10	
Fixed and Variable	4.5	4.6	1.4	1.4	1.4	1.4	1.1	1.1	1.2	18.1
Less: Variable	1.4	1.4	0.1	0.1	0.1	0.2				3.3
Fixed Production	3.1	3.2	1.3	1.3	1.3	1.2	1.1	1.1	1.2	14.8
Maintenance and repairs	7.4	7.4	1.1	1.1	1.1	1.1	1.1	1.1	1.1	22.5
Purchase site power and standby	1.5	1.5		0.1	0.1		0.1	0.1	0.1	3.4
Generation Admin	2.0	2.0	0.6	0.6	0.6	0.6	0.4	0.4	0.3	7.4
Production O and M	14.0	14.1	3.0	3.0	3.0	2.9	2.7	2.7	2.7	48.1
Corporate Services	2.8	2.8	0.8	0.8	0.8	0.7	0.5	0.5	0.5	10.2
Generation Pool Access	2.4	2.3	0.9	0.9	0.9	0.9	0.4	0.4	0.4	9.5
Total	19.2	19.2	4.7	4.7	4.7	4.5	3.6	3.6	3.6	67.8

Source: Schedules G-1U, G-4 and G-4U

The Intervenors raised issues with respect to O and M expenses that will be discussed under the following topics:

(A) Fixed and variable production
(B) Maintenance and repairs
(C) Generation administration
(D) Corporate services
(E) Summary

(A) Fixed and Variable Production

EPGI forecast fixed and variable production costs to increase by $3.0 million from 1998 to 1999 and to decrease by $0.2 million from 1999 to 2000.

EPGI noted the fixed production cost had been relatively stable from 1996 through 1998. The increase in the 1998 forecast relative to the 1996 and 1997 amounts were mainly in staff costs, largely due to wage and salary inflation. For salaries and wages, EPGI used an adjustment factor of 3.2% in each of 1999 and 2000. This adjustment factor was in keeping with EPGI's expected trend in salary and wage increases. EPGI explained the significant increase in fixed production costs in 1999 and 2000 was due to a number of factors including wage and salary costs, plant engineering, and information services. EPGI provided the following as a more detailed description of each factor on a year-over-year basis.

EPGI explained the 1999 forecast reflected a $1.2 million increase in wages and salaries. EPGI stated a portion of the wages and salaries increase, approximately $0.6 million, resulted from inflation with the remaining $0.6 million due to the following two factors:

- First, the addition of three new staff positions, consisting of a database administrator for the EMPAC work management system, an electrical and instrumentation technician at Clover Bar, and a mechanical apprentice at Genesee.
- Second, increased labour and temporary support in operations and stores were forecast due to the higher level of turnaround activity in 1999. Plant engineering costs increased $0.4 million in 1999, in both direct plant costs and increased engineering charges from technical services in Generation Administration, for both turnaround support and general increases in plant engineering activities.

EPGI explained the 1999 forecast reflected $0.9 million increase in direct information services costs within EPGI. This increase was the result of maintenance, training, and support for the new EMPAC work management system, with smaller cost increases in workstations and printer support, and licensing fees. EPGI continued that smaller increases included $0.2 million due to a reclassification of training costs previously included with human resources in Generation Administration and $0.2 million increase in materials and supplies due to a reclassification with maintenance and an increase for chemical input costs.

EPGI explained the 2000 forecast represented a decrease of $0.2 million from the 1999 forecast. EPGI stated a salary and wage increase of $0.6 million due to escalation for 1999 was partially offset by a reduction of $0.1 million for operational support for planned turnarounds, resulting in an overall increase of $0.5 million. EPGI stated plant engineering costs decreased by approximately $0.5 million due to the reduced turnaround activity in 2000.

Position of the FIRM Customers

The FIRM Customers, using information from the above table, indicated that the fixed and variable operations expense increased $3.0 million from $15.3 million in 1998 to $18.3 million in 1999 with a modest reduction of $0.2 million from 1999 to 2000. The FIRM Customers noted that a breakdown of this expense by year was provided in MI-EPGI.05. The FIRM Customers recommended labour expense be reduced by $1.0 million in both 1999 and 2000 and salary

expense by $0.8 million in each test year noting that approximately 57% of the labour reduction and 40% of the salary reduction would apply to the fixed and variable operations.

The FIRM Customers noted that contractors and consultants contributed to the increase in fixed and variable operations. From MI-EPGI.05, the FIRM Customers noted EPGI's response that contractors and consultants should be viewed in conjunction with consulting engineering.[179] The FIRM Customers calculated the total increase from 1998 to 1999 for these two items at $0.3 million and a $0.1 million decrease from 1999 to 2000.

The FIRM Customers noted EPGI's explanation that the increase from 1998 to 1999 was due to increased turnaround activity and an increase in consulting assistance with respect to technical support for the work management system. The FIRM Customers submitted the turnaround activity in 1999 was comparable to that in 1998 and, accordingly, recommended the $0.3 million increase in 1999 over 1998 and the $0.2 million increase in 2000 over 1999 should not be approved.

The FIRM Customers also stated that office and general contributed $0.5 million to the increase in 1999 over 1998. The FIRM Customers noted EPGI's reasons for the increase in office and general as increased training on new computer and operational systems, with minor increases for memberships and office expenses.[180] However, the FIRM Customers submitted the increased training on computer and operational systems, as well as other office expense, were ongoing activities and should not result in increased costs in the test years, as these expenses should be offset by ongoing efficiencies. Consequently, the FIRM Customers recommended the fixed and variable operations costs be reduced by $0.5 million in both 1999 and 2000.

In summary the FIRM Customers recommended the following reductions to fixed and variable operations:

- The labour and salaries component of production costs should be reduced by $0.9 million in each of 1999 and 2000;
- The contractors and consultants and consulting engineering costs should be reduced by $0.3 million in 1999 and $0.2 million in 2000; and
- The office and general expense should be reduced by $0.5 million in each of 1999 and 2000.

Position of EPGI

EPGI noted the FIRM Customers' argument of a 57% reduction to the increase in labour expense and 40% reduction to the increase in salary expense. EPGI claimed the 57% and 40% figures were arbitrary and unsupported by the evidence. EPGI submitted that detailed explanations were

[179] Exhibit 47, Tr. p.1030-1032(c)
[180] Exhibit 47, Tr. p.1030-1032(c)

provided for the costs in the fixed and variable operations thereby explaining and demonstrating the reasonableness of EPGI's costs.

EPGI noted the FIRM Customers' argument that the $0.3 million increase in contractors and consultants costs in 1999 over 1998 and the $0.2 million increase in 2000 over 1998 should not be approved.

EPGI asserted this argument was without merit. The FIRM Customers' suggestion was inconsistent with the table provided in response to an undertaking in Exhibit 47, Tr. p.1030 to 1032. EPGI indicated the table showed that contractors and consultants, together with consulting engineering costs, increased by $0.29 million from 1998 to 1999, and then decreased by $0.1 million from 1999 to 2000. EPGI submitted that the $0.29 million increase from 1998 to 1999 was reasonable irrespective of whether or not turnaround activity was comparable between the two years.

The FIRM Customers also ignored evidence showing that the increase was due to an increase in consulting and technical assistance costs relating to EPGI's new Work Management System.[181] EPGI submitted the record demonstrated that EPGI's forecast contractors and consultants costs for 1999 and 2000 were reasonable and should be approved by the Board.

EPGI stated the FIRM Customers' assertion that EPGI's forecast office and general costs should be reduced by $0.5 million in each of 1999 and 2000 because increased costs for training on computer and operational systems should be offset by ongoing efficiencies.

EPGI explained that the requirement for increased training was related to EPGI's new Work Management System as found in Exhibit 47, Tr. p.1030-1032. EPGI stated this requirement was not an ongoing activity, but, rather, a new operational requirement in 1999 and 2000 following the installation of the system in 1998. EPGI also explained that the final module was scheduled for installation in 2000.[182]

Board Findings

The Board notes that the salaries and wages portion proposed by EPGI were adjusted according to the Board Findings in the Incentive Compensation section of this Decision.

The Board has reviewed the costs associated with the contractors and consultants and accepts EPGI's explanation that the two cost categories of consulting engineering and contractors and consultants should be combined when reviewing the costs. The Board accepts EPGI's explanation for the additional costs of maintenance, training and support being incurred to implement the new EMPAC Work Management System, and accepts the forecast costs as reasonable.

[181] Exhibit 47
[182] ENMAX-EPGI-36; IPCAA-EPGI-44

The Board considers the comments by the FIRM Customers to be valid with respect to the office and general category. The Board considers that the purpose of incurring costs for training is to promote operational efficiencies. The Board notes it is not known when the timing of the training will take place during the year in order to take advantage of the operational efficiencies that would result, and therefore allows only half the requested increase in each of the years 1999 and 2000. The Board directs EPGI, in its refiling, to reduce the expenses associated with office and general by $0.25 million in each of 1999 and 2000.

The Board has summarized the allowed costs for fixed and variable production costs at the end of this section.

(B) Maintenance and Repair

EPGI forecasted maintenance and repair expenses of $25.6 million in 1999, which is $2.5 million higher than the amount approved in EPGI's 1996 GTA Refiling and $1.8 million higher than EPGI's 1998 reforecast. EPGI forecasted the maintenance expense to decline $3.1 million in 2000. A comparison of annual maintenance and repair expenses at Genesee, Clover Bar and Rossdale was provided in the Tables above.

EPGI stated the 1998 reforecast maintenance expense was higher than the amount in the 1996 Refiling. EPGI explained that, although maintenance expense decreased at Genesee, the decrease was offset by an increase at Clover Bar due to an extensive 98 day turnaround to complete overhauls of both the turbine and boiler.

EPGI stated the 1999 forecast maintenance expense for Genesee and Rossdale was comparable to the 1998 reforecast, however, the 1999 maintenance expense for Clover Bar was forecast to be $9.2 million in 1999, an increase of $1.8 million over the 1998 reforecast. EPGI explained the largest portion of the increase was due to the advancement of boiler and turbine maintenance work, on Units 3 and 4, to coincide with the timing of their scheduled outages for the capital installation of the Y2K compliant distributed control systems (DCS). EPGI stated these DCS installations had been accelerated to 1999, from their previously scheduled installation in 2000 and 2001, in order to ensure Y2K compliance by 1 January 2000. EPGI explained a major turnaround of Unit 2 was scheduled to complete overhauls of both the turbine and the boiler, similar in scope to the major turnaround that was required for Unit 1 in 1998.

EPGI noted the maintenance expense for Clover Bar was forecast to decline by $3.1 million in 2000 to levels that were comparable to actually incurred levels for 1996, 1997 and 1998. EPGI explained the decrease was due to minor turnarounds scheduled for two Clover Bar units in 2000. EPGI noted the decrease in maintenance expense at Clover Bar was partially offset by increased forecast maintenance expense at Genesee since there were two minor turnarounds scheduled versus one major turnaround in 1999. As described during the 1996 GTA, EPGI reiterated that the Genesee plant was on a three-year rotation. A major turnaround would be

performed on Unit 2 in the first year, a major turnaround would be performed on Unit 1 in the second year and a minor turnaround would be performed on each unit in the third year.

EPGI noted the maintenance costs for Rossdale were forecast to be $3.1 million in 1999 and $3.4 million in 2000. EPGI explained the 1999 amount represented a decrease of $0.5 million from the 1998 reforecast and a decrease of $0.3 million from the 1996 GTA Refiling. A boiler certification and minor turnaround on Unit 10 was planned during 1999, with a major turnaround on Unit 8 planned for 2000. EPGI indicated the current schedule for repowering and life extension of Unit 8 called for the turbine generator refurbishment work to be done in 2000 during the turnaround. EPGI submitted the refurbished Unit 8 would be available for service following the turnaround.

Position of ENMAX

ENMAX noted that Schedule G-4U of the Application displayed the annual maintenance and repair costs for Genesee as $13 million and $15 million for 1999 and 2000 respectively and indicated operating costs of $9 million each year for a total operating and maintenance cost at Genesee of $22-$24 million in 1999 and 2000. ENMAX suggested, by contrast, the Keephills units were forecast to have an O&M cost of $10.5 million in each year. ENMAX submitted EPGI had no explanation for why the cost differentials between the two units existed. ENMAX recognized that there may be differences among units in terms of capital spending but this significant difference between units of a similar size and vintage should be explained. ENMAX stated the utilities had performed benchmarking studies of other generating units throughout North America, but could not explain differences between costs at their own generating units located beside each other.

ENMAX expressed an additional concern on the variance between forecast and actual operations and maintenance expenses for Genesee. ENMAX noted that the difference between Genesee forecast and actual expenses in 1996 was $4.5 million. ENMAX suggested the Genesee operations and maintenance costs were higher than those of a comparable unit and that the actual expenses had been below forecast by a significant amount provided support for a reduction in allowed forecast operations and maintenance expense for Genesee. ENMAX recommended, in the absence of any information or explanation from EPGI, a reduction of the forecast Genesee operating and maintenance expenses by $5 million in each of 1999 and 2000.

Position of the FIRM Customers

The FIRM Customers prepared the following table as a summary of EPGI's maintenance and repair expenses:

2. EPGI
(c) Cash Operating Expense

	$ million					
	1996 Forecast	1996 Actual	1997 Actual	1998 Reforecast	1999 Forecast	2000 Forecast
Genesee-Regular	12.4	8.9	8.6	8.2	8.5	8.8
Genesee-Planned	3.2	2.2	6.4	4.6	4.8	6.0
Clover Bar-Regular	2.8	2.9	3.3	3.1	2.7	3.3
Clover Bar-Planned	1.3	1.3	0.8	4.3	6.5	1.0
Rossdale-Regular	2.2	1.8	1.6	1.6	2.4	2.3
Rossdale-Planned	1.2	1.5	0.0	2.0	0.7	1.1
Total	**23.1**	**18.6**	**20.7**	**23.8**	**25.6**	**22.5**
Total-Regular	17.4	13.6	13.5	12.9	13.6	14.4
Total-Planned	5.7	5.0	7.2	10.9	12.0	8.1
Total	**23.1**	**18.6**	**20.7**	**23.8**	**25.6**	**22.5**

Source: X13, p.16, Table 5 and ENMAX-EPGI.14

The FIRM Customers stated the above table illustrated that EPGI's 1996 actual expenses were $4.5 million (or 19.5%) lower than the amount approved by the Board. In the 1996 GTA, the FIRM Customers submitted that EPGI's maintenance and repair expense should have been reduced by $3.9 million. EPGI, on the other hand, argued there was no rational basis for adopting such a position.

For the 1999/2000 GTA, the FIRM Customers submitted that the Board had evidence of EPGI's forecasting history and asserted this history must be considered relevant and material to the establishment of maintenance and repair expenses for the 1999 and 2000 test years. The FIRM Customers also noted EPGI's refusal to provide historical forecast or actual information prior to 1996, despite requests from interested parties.

Genesee

The FIRM Customers noted that the Genesee plant was on a three-year rotation. In 1999, EPGI forecasted a major turnaround on Genesee 1 at a cost of $4.8 million. The FIRM Customers noted that this total was comprised of $1.8 million for boiler refurbishment, $1 million to $2 million for IP and LP rotor work and approximately $1.5 million for work on boiler auxiliaries such as fans and pumps.[183]

With regard to the cycles on boiler auxiliaries, the FIRM Customers submitted the forecast cost was overstated. The FIRM Customers claimed the only piece of actual cost evidence respecting boiler overhauls was the $1.9 million spent in 1997 for boiler refurbishment which included

[183] Tr. p.1437, l.12

about $1.8 million for boiler work and the remainder for auxiliaries. The FIRM Customers noted that, from the 1997 actual costs, an amount of about $0.1 million could be inferred for boiler auxiliary work.

The FIRM Customers suggested that, in argument, EPGI alluded to the details provided with respect to the $4.8 million maintenance expense forecast for the Genesee 1 unit in 1999. The FIRM Customers noted the response in Exhibit 56, Tr. p.1439 was a material revision to the testimony given during cross-examination.. The FIRM Customers stated that Exhibit 56 indicated boiler maintenance costs of $2.5 million, turbine maintenance costs of $1.8 million and $0.7 million for auxiliaries and other. Mr. Topping's testimony was:

> Work on auxiliaries like fans and pumps is done regularly in every minor or major as it comes up, and they are alternated between the auxiliaries, so we pick up the auxiliaries with the hours on them, the operating hours that have accumulated that require the major work at the particular minor or major of the unit itself.

When queried during cross-examination, the following exchange occurred:

> Q. Would you have the costs related to the boiler pumps from the last turnaround?
>
> A. MR. TOPPING: The turbine and boiler work, generally, is very close as you go from turnaround to turnaround, especially the boiler proper, and the remaining work is the auxiliaries.[184]

The FIRM Customers submitted, contrary to EPGI's testimony, the boiler costs listed in Exhibit 56 were significantly different from one year to the next. Further, the expenses for auxiliaries shown at $0.7 million and supposedly done at the time of every minor or major turnaround, were significant costs ($0.7/$2.0=35%) in relation to the boiler proper maintenance costs. These levels of costs for boiler auxiliaries did not fit with the boiler maintenance plus auxiliaries maintenance costs of $1.9 million in 1997 for Genesee 2 and $2.2. million in 1996 for Genesee 1 as shown on Table 5 of the Application. The $0.7 million expended on boiler auxiliaries in 1997 did not demonstrate the scope of the work would be the same in 1999.

The FIRM Customers submitted because numbers and explanations could change so significantly and be so contradictory perhaps bore testimony to the preliminary nature of EPGI's forecasts and cast doubt as to the reliability and credibility of the information. The FIRM Customers submitted the Board must consider the overall level of the forecasts and decide whether all of the probable cost components EPGI included were likely to be incurred at the forecast level. As indicated in the FIRM Customers' argument, the evidence demonstrated EPGI's planned maintenance expense in 1996 was 12.3% less than forecast shown on the table

[184] Tr. p.1438, l.16

above. The FIRM Customers further submitted that this apparent, inherent bias towards forecasting for every possible expense component should be taken into account when determining the appropriateness of the 1999 and 2000 maintenance expenses, particularly as many of these expenses might not materialize on an actual basis.

Based on the foregoing, the FIRM Customers recommended the Board adopt the $1.8 million level of expenditure that EPGI first indicated represented the normal boiler maintenance cost. The FIRM Customers noted EPGI did not suggest this number was subject to check. Further, the $0.7 million forecast for boiler auxiliaries appeared high in relation to some of the combined boiler plus auxiliary maintenance costs in 1997 for Genesee 2 and in 1996 for Genesee 1. Accordingly, the FIRM Customers recommended a reduction of $1.4 million to the 1999 Genesee 1 planned maintenance.

The FIRM Customers noted that in 2000 EPGI planned minor turnaround work on both Genesee units for a cost of $3.0 million each. The FIRM Customers also noted the turnaround costs included $2.0 million for boiler refurbishment and $1.0 million for turbine steam valve replacement. The FIRM Customers calculated the percentage increase in boiler refurbishment costs from 1999 to 2000 at 11% (i.e. $1.8 million to $2.0 million). The FIRM Customers submitted this increase was excessive and should be limited to the 1999 level considering inflation to be offset by productivity improvements.

With regard to the turbine steam valve replacement, the FIRM Customers stated that EPGI's evidence was the result of some deterioration in the turbine steam valves detected at the time of the Unit 2 turnaround in the fall of 1998. The FIRM Customers noted the replacement parts were scheduled to arrive in late 1999 or early 2000 to coincide with the minors. However, the FIRM Customers noted that it seemed unlikely this replacement would cost as much as $1.0 million given it was to take place during the scheduled turnarounds for both units. As a result, the FIRM Customers submitted the Board should make an assessment as to the reasonableness of the $1.0 million forecast.

Clover Bar

The FIRM Customers indicated that EPGI planned minor turnaround work for Clover Bar Units 3 and 4 in 1999 at a cost of $1.2 million each. The FIRM Customers noted that EPGI indicated the turnarounds for these units had been advanced to coincide with the timing of their scheduled outages for capital installation of Y2K compliant distributed control systems.

The FIRM Customers reviewed and noted that historical minor turnaround costs were in the $0.4 million (1998) to $0.7 million (1996 at $1.3 million for Units 1 and 3) range.[185] The FIRM Customers submitted the $1.2 million forecast for each of Units 3 and 4 was excessive and recommended the forecasts, related to these minor turnarounds, be reduced by $0.5 million each, for a total of $1.0 million in 1999.

[185] EAL-EPGI.14

The FIRM Customers noted that EPGI also forecast $4.1 million for a major turnaround at Clover Bar Unit 2 for 1999 and described the work to be performed as follows:

- On Clover Bar Unit 2, for this year, the turnaround starts in April. EPGI will be doing blade replacements on the high pressure and low pressure turbines. EPGI will be doing nozzle block replacements on the high pressure and intermediate pressure turbines.
- The major work in the boiler will replace the super-heater clips that support the super-heater, economizer work, and work on the buckstays. The work will take three months which is about a twelve-week outage.

The FIRM Customers also noted that, in addition to the above maintenance expense, EPGI forecasted significant capital additions for Unit 2 in 1999, including:

	Million
Low pressure turbine last stage blade replacement	$1.272
High pressure turbine first stage blade replacement	$0.425
Intermediate pressure turbine nozzle block	$0.266
Intermediate pressure turbine nozzle block refurbishment	$0.213
High pressure nozzle segment replacement	$0.202
Super-heater clip replacement	$0.904
Buckstay corner upgrades	$0.117
Economizer modifications	$0.075
Total	**$3.474**

Source: ENMAX-EPGI.35(c)-(d)

The FIRM Customers suggested the description of items included in the capital additions forecast appeared to be the same as those under the O&M forecast described by EPGI. The FIRM Customers submitted that the Board must ensure no duplication of costs exist between the capital and the O&M forecasts and, if there is, the necessary adjustments to either capital or O&M must be made.

Rossdale

The FIRM Customers noted that, from EAL-EPGI.14, EPGI indicated that regular maintenance at Rossdale was increasing by 50% between 1998 and 1999. The FIRM Customers stated that this increase was in sharp contrast to the $1.6 million level EPGI successfully maintained at Rossdale in 1997 and 1998. The only explanation EPGI provided for the increase was inflation. In the absence of any other evidence to support such an increase, the FIRM Customers recommended the Rossdale regular maintenance be set at $1.6 million for 1999 and 2000 to reflect escalation, offset by productivity improvements. The FIRM Customers suggested EPGI's

increase in Rossdale O&M was particularly unsound given the assumption, for ratemaking purposes, that the plant will be closed in 2000. Any O&M costs incurred to keep the plant open after 2000 should be disallowed as inconsistent with ratemaking for depreciation and decommissioning.

In summary, the FIRM Customers made the following recommendations with respect to maintenance and repair expenses:

- The Board must have regard to the forecasting history of EPGI in setting the level of this expense item;
- The 1999 forecast major maintenance cost for Genesee 1 should be reduced by $1.4 million as the forecast cost for overhaul of boiler auxiliaries appeared to be high in relation to work performed in prior years;
- The 2000 forecast major maintenance for Genesee 1 and Genesee 2 should be reduced by $0.2 million each for a total of $0.4 million to reflect reductions in boiler maintenance costs;
- The Board should assess the reasonableness of the turbine valve replacement cost of $1.0 million each for Genesee 1 and Genesee 2 in 2000;
- The 1999 forecast minor maintenance on Clover Bar 3 and 4 should be reduced by $0.5 million each for a total of $1.0 million;
- The Board should ensure no duplication exists between capital and O&M with respect to the Clover Bar 2 major maintenance in 1999; and
- The regular maintenance costs at Rossdale should be reduced by $0.8 million and $0.7 million in 1999 and 2000, respectively.

Position of EPGI

EPGI noted that ENMAX asserted that the generation maintenance and repair expense should be reduced by $5 million in each of 1999 and 2000 based on the difference between EPGI's forecast and actual costs in 1996 of $4.5 million. EPGI explained, the variance in 1996 was due to (i) more work having been performed under warranty than was forecast and (ii) changes in the procedures and methodologies used for scheduling and performing maintenance. EPGI submitted that no Intervenors challenged the reasons for the difference between forecast and actual costs in 1996 in their final arguments.

EPGI stated that ENMAX also attempted to support its assertion by comparing EPGI's forecast O&M expense for Genesee to TransAlta's forecast O&M expense for its Keephills units, by stating that EPGI had not provided an explanation as to why EPGI's costs should be different. EPGI emphasized this comparison was of no assistance to ENMAX's position.

EPGI provided a list of factors that would have to be considered in any comparison of Genesee and Keephills O&M costs, including (i) the cost components included by each utility in O&M, (ii) the manner in which corporate services costs were allocated, (iii) the differences in coal

content, (iv) the operating characteristics, and (v) the design philosophies of turbines, boilers and other constituents of the plants. EPGI suggested that ENMAX had provided no analysis of these factors that suggested the costs were comparable. Accordingly, EPGI submitted the comparison was misleading and unhelpful.

EPGI responded to the FIRM Customers' concerns regarding the generation maintenance and repair expense relating to specific plants.

Genesee

EPGI stated the FIRM Customers argued that EPGI's 1999 forecast cost of $1.5 million for work on Genesee boiler auxiliaries should be reduced to $0.1 million. EPGI noted the FIRM Customers based the suggestion on the actual cost of $1.9 million for EPGI's 1997 boiler refurbishment at Genesee which included about $1.8 million for boiler work and the remainder for auxiliaries.

EPGI noted that the assertion was inconsistent with EPGI's evidence set out in its response to an undertaking on Exhibit 56, Tr. p.1439, showing the cost breakdowns for Genesee turnaround work. EPGI asserted the response demonstrated that the forecast costs for auxiliaries in 1999 and the actual costs in 1997 for auxiliaries on the same unit were both $0.7 million making the FIRM Customers' calculation of $0.1 million incorrect. EPGI noted the portion of forecast maintenance and repair costs for auxiliaries for 1999 was the same as the actual cost in 1997.

EPGI stated the FIRM group argued that EPGI's forecast Genesee boiler refurbishment cost for 2000 of $2.0 million per unit should be limited to the 1999 forecast amount of $1.8 million considering inflation offset by productivity improvements.

EPGI submitted this suggestion was also inconsistent with EPGI's response to the undertaking on Exhibit 56, Tr. p.1439. EPGI noted the response demonstrated that the forecast costs for boiler work on Unit 1 during the 1999 major turnaround was $2.5 million rather than the $1.8 million cited by the FIRM Customers. EPGI explained the forecast cost of the Units 1 and 2 boiler work in 2000 was $0.5 million less than the forecast for boiler work during the major on Unit 1 in 1999.

EPGI noted the FIRM Customers argument that the Board should assess the reasonableness of the $1 million forecast cost of steam valve replacements for 2000, wherein the FIRM Customers, stated "it seems unlikely this replacement would cost as much as $1 million given it is to take place during the scheduled turnarounds for both units."

EPGI countered that "it seems unlikely," to the FIRM Customers, that this forecast cost was high provided no basis for the Board to reduce this forecast. Further, EPGI noted that the $1.0 million forecast cost was not merely in respect of the replacement of defective parts, but was also for the first major refurbishment of the valves for each unit in accordance with manufacturer's

recommended inspection interval.[186] EPGI submitted the evidence relating to this forecast cost demonstrated that the cost was reasonable.

Clover Bar

EPGI noted the FIRM Customers' argument that EPGI's forecast cost for Clover Bar Units 3 and 4 minor turnaround work in 1999 of $1.2 million per unit should be reduced by $0.5 million based on historical minor turnaround costs ranging from $0.4 million (1998) to $0.7 million (1996).

EPGI submitted this suggestion was without merit. EPGI stated the referenced historical turnarounds were not comparable to the 1999 turnarounds. The 1996 Unit 1 turnaround consisted of only a 10-day boiler re-certification, and the 1996 Unit 3 turnaround was a 22-day minor. The combined cost of these turnarounds was $1.3 million. EPGI further stated the 1997 Unit 4 turnaround consisted only of a 12-day boiler re-certification at a cost of $0.8 million. EPGI submitted that the forecast Unit 3 and 4 turnarounds for 1999 contain both boiler and turbine work and were scheduled for 49 days each, which was far longer than the previous turnarounds.

EPGI referred to the FIRM Customers argument that the Board must ensure that there was no duplication of costs between EPGI's forecast generation maintenance and repair and capital expenditures relating to the Clover Bar Unit 2 major turnaround scheduled for 1999.

As stated by EPGI during cross examination, there was no duplication of costs as the maintenance and repair costs and the capital expenditures each related to different projects and scopes of work.

Rossdale

EPGI noted the FIRM Customers argued that Rossdale "regular maintenance" should be set at $1.6 million in each of 1999 and 2000 "to reflect escalation, offset by productivity improvements." EPGI also noted the FIRM Customers' suggestion that the increase in Rossdale generation O & M was particularly unsound given that the plant will be closed in 2000 and, therefore, any O&M costs incurred to keep the plant open after 2000 should be disallowed.

EPGI stated the FIRM Customers did not provide any substantiation for its position from the evidence, other than a comparison with historical costs. EPGI submitted there was no evidence that the scope of the work upon which these costs were based was similar to that performed in 1997 and 1998 and that the costs were, therefore, comparable. EPGI stated the increase in regular routine maintenance in 1999 and 2000 relative to prior years was due to the general increase in operating hours which the Rossdale units resulting from the tight supply conditions in the province. EPGI reiterated that maintenance costs, for the gas-fired units, were a function of

[186] Exhibit 43; Tr. p.1010-1011

both operating hours and equivalent operating hours as a result of start-ups previously explained in EAL-EPGI.06 and MI-EPGI.06.

EPGI submitted there was no evidence to suggest that the expenditures were not necessary to provide for the ongoing operation of the units in 1999 and 2000. Further, EPGI noted that in spite of the increase in regular maintenance, the total forecast maintenance and repair costs for Rossdale in 1999 and 2000 were lower than 1998 actuals and were comparable to 1996 actuals.

Board Findings

The Board notes EPGI's comments concerning the difficulties of comparing EPGI's maintenance and repair costs with those of the Keephills plant. The Board accepts EPGI's explanation of the factors that require consideration for any comparison of Genesee maintenance and repair costs with those of the Keephills plant. The Board rejects ENMAX's recommendation of reducing maintenance and repairs by $5.0 million for both 1999 and 2000.

The Board notes that the turnaround program established by EPGI for Genesee follows a pattern of a major for each unit in subsequent years and a minor for both units in the third year. The Board understands that during 1999, the major turnaround is for Genesee Unit 1 and that during 2000, the minor turnaround will occur on both units.

The Board notes, that the FIRM Customers suggested three concerns with respect to the Genesee Plant. The first concern was the level of costs for the overhaul of boiler auxiliaries for Genesee Unit 1 in 1999. The FIRM Customers recommended the costs for auxiliaries should be kept at the same level of $0.1 million, as was inferred from the 1997 costs, to perform a boiler refurbishment with an overhaul of auxiliaries. The Board notes EPGI's response that the calculation was inconsistent with the response to the undertaking, Exhibit 56, Tr. p.1439 wherein the cost for auxiliaries and other was $0.7 million.

The Board considers that there was some confusion in determining the individual component costs before EPGI submitted Exhibit 56, Tr. p.1439. The Board finds that, notwithstanding the confusion regarding the component costs of the Genesee Unit 1 turnaround, the costs for the overhaul of boiler auxiliaries is excessive. Therefore, the Board directs EPGI, in its refiling, to reduce the costs associated with the overhaul of boiler auxiliaries by $0.3 million in 1999.

The Board notes the FIRM Customers' second concern related to the excessive cost of $0.2 million for the boiler refurbishment of $2.0 million included in the turnaround costs for both Genesee units in 2000. The Board notes EPGI's response that $2.5 million was the correct cost of the boiler refurbishment rather than the $1.8 million cited by the FIRM Customers. The Board accepts that, for two boiler refurbishments, the costs for 2000 would more reasonably approximate $2.5 million. The Board accordingly will not make any adjustment to the boiler refurbishment costs for the year 2000.

The Board notes the third concern of the FIRM Customers, the cost of repairing the turbine steam valves for $1.0 million during 2000. The Board notes EPGI's explanation that the cost was not only for the replacement of defective parts, but also for the first major refurbishment for each unit in accordance with the manufacturer's recommended inspection interval. The Board accepts EPGI's response as reasonable and allows the cost as part of the turnaround costs for 2000.

With respect to Rossdale, the Board agrees with the FIRM Customers that the Rossdale regular maintenance should be set at $1.6 million and any expenditures beyond this level should be accounted for through the PPA process. The Board considers that this is consistent with the historical level for maintenance. Therefore, the Board directs EPGI, in its refiling, to reduce the 1999 regular maintenance forecast for Rossdale by $800,000 ($2.4 million less $1.6 million) and for 2000 by $700,000 ($2.3 million less $1.6 million).

The Board has summarized the allowed costs for maintenance and repairs at the end of this section.

The Board notes the salaries and wages portion proposed by EPGI were adjusted according to the Board Findings in the Incentive Compensation section of this Decision.

(C) Generation Administration

EPGI forecast generation administration costs of $9.1 million in 1999 and $7.4 million in 2000 and included two items that needed to be accounted for when comparing to prior years:

- EPGI's share of the costs to fund the IAT was $1.3 million for 1999 and $0.3 million for 2000.
- Information services costs directly assigned to EPGI from corporate services were $0.8 million in 1999 and $0.6 million in 2000. These costs consisted of direct staff and related costs assigned to EPGI, license fees for the EMPAC work management system, and communication lines to Genesee. Previously, EPGI reflected parts of these costs in corporate services allocation for information services.

EPGI suggested that removing these two items restated Generation Administration costs of $7.0 million for 1999 and $6.5 million for 2000.

EPGI indicated the restated amount for 1999 of $7.0 million represented an increase of $1.2 million from the 1998 forecast. EPGI explained the majority of the increase was in technical services for (i) an increase of $0.9 million as a result of increased engineering support for plant turnarounds, (ii) regulatory support costs, (iii) filling of vacant positions that existed during 1998, and (iv) salary and wage escalation.

2. EPGI
(c) Cash Operating Expense

EPGI explained that energy and risk management costs had increased $0.5 million, due to (i) increased staff costs, (ii) higher pool trading costs, and (iii) increased consulting costs for risk management and load forecasting. EPGI noted that other minor increases were generally offset by a $0.3 million reduction in human resources, resulting from a centralization of two staff to corporate services and a reallocation of training costs to fixed operations.

EPGI stated Generation Administration of $6.5 million, on a restated basis for 2000, represented a decrease of $0.5 million from the restated 1999 levels. This decrease was due to reductions in technical services for reduced plant turnaround support and in direct information services costs.

Position of the FIRM Customers

The FIRM Customers provided a history of Generation Administration expenses which was summarized as follows:

1996 Forecast $ million	1996 Actual $ million	1997 Actual $ million	1998 Reforecast $ million	1999 Forecast $ million	2000 Forecast $ million
6.1	5.4	5.6	5.9	9.1	7.4

Source: Sch.G-4

The FIRM Customers indicated a $3.2 million increase in 1999 over 1998 and a reduction of $1.7 million from 1999 to 2000. The FIRM Customers noted that a breakdown of this expense by year was provided in MI-EPGI.07. The FIRM Customers recommended reducing the total EPGI salary expense by $0.2 million in both 1999 and 2000 of which 40% would apply to the generation administration category.

The FIRM Customers noted that one of the significant components of this expense category was $1.3 million in IAT costs for 1999 and $0.3 million for 2000. The FIRM Customers submitted all external costs related to IAT activities should be routed through the hearing costs reserve after approval under s.78 funding guidelines.

The FIRM Customers stated the contractors and consultants component of generation administration increased by $0.6 million in 1999 over 1998 and decreased by $0.5 million in 2000 compared with 1999. The FIRM Customers noted that EPGI suggested the increase in 1999 was primarily due to increased technical training as shown on Exhibit 47, Tr. p.1030(a). The FIRM Customers submitted that technical training costs were ongoing activities and would not result in higher costs during the test years as these costs would be offset by ongoing efficiencies. Therefore, the FIRM Customers recommended reducing the generation administration by $0.6 million in 1999.

In summary, the FIRM Customers recommended the following reductions for generation administration:

- The salaries component of this category be reduced by $0.3 million in each of 1999 and 2000;
- The external costs related to IAT activities be routed through the hearing costs reserve and subject to approval under s.78 guidelines; and
- The contractors and consultants costs be reduced by $0.6 million in 1999.

Position of EPGI

EPGI noted the FIRM Customers argued that 40% of its recommended reduction to salary expense should be applied to EPGI's Generation Administration costs. EPGI submitted that detailed explanations were provided for the costs in the Administration category which explained and demonstrated the reasonableness of EPGI's costs. EPGI claimed that the evidence also demonstrated that the FIRM Customers' suggested percentage allocations were arbitrary and unsupported by evidence, and submitted the reduction should be rejected.

EPGI stated the FIRM Customers suggested that all external costs related to IAT activities should be routed through the hearing cost reserve account after approval under section 78 funding guidelines. EPGI submitted the FIRM Customers provided no basis for this suggestion. EPGI's approach to its forecast share of IAT costs of $1.3 million for 1999 and $0.3 million for 2000 was consistent with the DRD (formerly the ADOE) directive that these costs be included as a component of the owners' 1999/2000 reservation prices. EPGI noted that all other costs associated with the implementation of the PPAs were dealt with through the hearing cost reserve account as the FIRM Customers suggested.

EPGI stated the FIRM Customers argued that the contractors and consultants component of generation administration for 1999 should be reduced by $0.6 million, as the increase "would appear [to be] primarily due to increased technical training." EPGI stated the FIRM Customers' argument failed to recognize the evidence demonstrating the various reasons for these increases. EPGI noted Exhibit 47 wherein, EPGI explained that the costs included increases in the number of contractors resulting from the implementation of the facilities management function, increases in load forecasting costs and risk management costs. EPGI also noted further information was provided in response to ENMAX-EPGI.20, which set out the amount of the increase associated with each of these categories of costs. EPGI suggests the FIRM Customers did not challenge this evidence.

Board Findings

The Board notes the salaries and wages portion proposed by EPGI were adjusted according to the Board Findings in the Incentive Compensation section of this Decision.

The Board agrees with EPGI that Section 78 costs are to be recovered through the annual reservation price and therefore rejects the FIRM Customers' recommendation that costs related to IAT activities be routed through the hearing cost reserve account.

The Board notes the position taken by the FIRM Customers that technical training costs are ongoing costs and should not result in higher costs as they should be offset by the ongoing efficiencies. The Board notes the comments by EPGI that the costs included increases resulting from the implementation of facilities management, load forecasting and risk management programs. The Board does not know when the actual training will occur and does not know how that will effect the operational efficiencies during 1999. Therefore, the Board directs EPGI, in its refiling, to include only $0.3 million of the $0.6 million requested increase for 1999.

The Board has summarized the allowed costs for general administration at the end of this section.

(D) Corporate Services

EPGI forecasted corporate service costs of $9.5 million in 1999 and $10.2 million in 2000. EPGI stated the primary increases in Corporate Services since 1996 were in Treasury, Controller, Information Systems, Human Resources and Environment. There had also been some changes to the allocation process since 1996 reflecting EPCOR's continuing refinement of the allocation process.

EPGI indicated the result was the allocation factors remained, generally, consistent with those used in 1996. EPGI provided detailed breakdowns and comparisons with previous years on Tables D-1 to D-3 in Appendix "D." EPGI stated the allocation reflected an increase in corporate service cost levels since 1996 that were offset by a reduction in the overall allocation rates to EPGI and were summarized on Table 6 in the Application.

The FIRM Customers

The FIRM Customers summarized EPCOR's Corporate Services costs and EPGI's share as follows:

	1996 Forecast $ million	1996 Actual $ million	1997 Actual $ million	1998 Reforecast $ million	1999 Forecast $ million	2000 Forecast $ million
EPCOR	22.6	22.9	25.2	24.2	24.6	25.4
EPGI	9.5	9.7	11.4	9.7	9.5	10.2

Source: Page 16, Table 6

The FIRM Customers noted that details of EPCOR's Corporate Services costs were provided in Schedule D-5. The FIRM Customers observed that one line item, information services, showed steady increases from year to year. The FIRM Customers noted EPCOR stated the increases reflected "the impact of a company such as Edmonton Power going from very, very little information systems support to one that is more appropriate for the nature and size of operation."[187] The FIRM Customers noted EPGI's explanation that the information systems costs reflected the progressive implementation of different phases of the CBIS system with the final one taking place in 2000.[188] In view of this explanation, FIRM Customers did not take issue with EPGI's proposed Corporate Service costs for 1999 and 2000, other than the allocation issues.

Position of EPGI

EPGI noted that the FIRM Customers did not take issue with forecast increases in Corporate IS costs relating to EPGI's staged implementation of different phases of the Corporation's CBIS system.[189] The Work Management System was one phase of the CBIS system and its costs were directly assigned to EPGI rather than being reflected in a Corporate Services allocation. EPGI explained the cost increases forecast for training were necessary for the ongoing implementation of this component of the CBIS system, were reasonable and prudent and should be approved by the Board.

Board Findings

The Board notes the salaries and wages portion proposed by EPGI were adjusted according to the Board Findings in the Incentive Compensation section of this Decision.

The Board has reviewed the Corporate Services costs and accepts EPGI's explanations for the accounts included in this category. The Board notes the Intervenors did not take issue with the costs, but rather with the allocation process. The Board accepts the forecast costs included in the Corporate Services total before allocation to EPGI. The Board considers the allocation process has been dealt with elsewhere in this Decision in Part 3–EPGI/EPTI, Section 1(b) Allocation of Common Costs.

The Board has summarized the allowed costs for Corporate Services expense at the end of this section.

(E) Summary

The Board has summarized the findings of Operations and Maintenance and adjustments to the Compensation Program in the table below:

[187] Tr. p.1033, l.18
[188] Tr. p.1034, l.20
[189] FIRM Customers Argument, page 124

2. EPGI
(c) Cash Operating Expense

OPERATIONS AND MAINTENANCE
($ millions)

	1999		2000	
	EPGI Requested	Board Approved	EPGI Requested	Board Approved
Fixed and Variable	18.3	18.0	18.1	17.9
Less: Variable	3.3	3.3	3.3	3.3
Fixed Production	15.0	14.7	14.8	14.6
Maintenance and repairs	25.6	24.5	22.5	21.8
Purchase site power and standby	3.4	3.4	3.4	3.4
Generation Admin	9.1	8.8	7.4	7.4
Production O&M	53.1	51.4	48.1	47.2
Corporate Services	9.5	9.5	10.2	10.2
Generation Pool Access	9.5	9.5	9.5	9.5
Compensation Program		(0.7)		(0.8)
Total	72.1	69.7	67.8	66.1

(5) Taxes Other Than Income Tax

EPGI forecasted property taxes of $11.1 million for both 1999 and 2000, representing a minor increase from the 1998 forecast amount of $11.0 million. The following table allocated the taxes:

TAXES OTHER THAN INCOME
($ millions)

	Genesee		Clover Bar				Rossdale			Total
	G1	G2	CB1	CB2	CB3	CB4	RD8	RD9	RD10	
1999	4.1	4.1	0.6	0.6	0.6	0.6	0.2	0.2	0.1	11.1
2000	4.1	4.1	0.6	0.6	0.6	0.6	0.2	0.2	0.1	11.1

Source: 1 Schedule G-1-Unit

No party took issue with EPGI's forecast property taxes.

2. EPGI
(c) Cash Operating Expense

In this section, the Board will determine an appropriate test year forecast for 1999 and an appropriate base line forecast for 2000 EPGI taxes other than income.

Board Findings

The Board notes that, in Part 1–General, Section 3(e) of this Decision, EPGI was directed to establish a deferral account for the year 2000 for EPGI taxes other than income, if the assessment rules are changed and are applicable in the 2000 tax year.

The Board has reviewed EPGI's forecast for land and building tax, machinery and equipment tax and business tax calculations. The Board notes the minor increases of less than 1% for each of 1999 and 2000 and notes that no party challenged these forecasts. The Board accepts, as reasonable, the total amount of $11.1 million for both 1999 and 2000.

(d) Depreciation

(1) Rossdale Decommissioning Costs

As part of its GTA, EPGI applied to revise the depreciation associated with decommissioning costs at the Rossdale Generating Plant. The Board had originally approved a $17.186 million decommissioning reserve for the plant in Decision U97065. EPGI applied for an increase in the decommissioning reserve to $36.7 million, later revised to $30.9 million.

The Board examined this application with regards to the EU Act as well as the recently enacted Generating Units Regulation AR 72/99 (GUR), issued 15 March 1999. The issues that arose with regards to the Rossdale decommissioning reserve were:

- The effect of the GUR on the ability of the Board to modify depreciation parameters;
- The effect of the GUR on the mid-year depreciation convention;
- The prudence of the cost increases applied for; and
- Whether certain decommissioning costs are more properly considered to be part of a life extension of existing generation or for the benefit of a non-regulated affiliate.

(A) Effect of the GUR on the Board's Ability to Modify Depreciation

Section 44(2) of the GUR states:

> For the purposes of the 1999-2000 General Tariff Application filed with the Board by owners of regulated generating units, the Board must assume that each of the following regulated generating units is decommissioned on the last day of the year shown for that unit:
>
> (a) Rossdale #8 -- 2000

(b) Rossdale #9 -- 2000
(c) Rossdale #10 -- 2000
...
(hh) Three Sisters #1 -- 2011

Section 44(3) of the GUR states:

> Where there is a conflict between:
> (a) the dates referred to subsections (1) and (2), and
> (b) the parameters established by the Board for the 1996 General Tariff Application,
>
> the Board must use the parameters established for the 1996 General Tariff Application in approving depreciation rates for the 1999 and 2000.

Position of ENMAX

ENMAX considered the revisions made to depreciation parameters regarding the Rossdale Generating Plant decommissioning costs to be in violation of section 44(3) of the GUR.

ENMAX noted that the wording between subsections (a) and (b) switched from a reference to "dates" to a reference to "parameters." ENMAX argued that this wording provided that the regulation has attempted to capture not only the date parameters, but also, in subsection (2), all the parameters that are used in the calculation of depreciation rates.

ENMAX noted that a conflict existed between the net salvage parameters and the decommissioning date of 31 December 2000. As Mr. Stout indicated:

> ...in as much as substantial sums for decommissioning have been expended prior to December 31st, 2000, that is that decommissioning in a sense has already begun in many respects, that could be viewed as conflicting with a December 31st, 2000, date of decommissioning in as much as decommissioning efforts have occurred in the years 1994 to date.[190]

In reply argument ENMAX submitted that the change in the decommissioning costs reflected in the 1999/2000 GTA, $30.9 million, as compared to the decommissioning costs reflected in the 1996 GTA, $17.2 million, was in violation of the GUR. Additionally, ENMAX made the following reply to specific comments in the EPGI argument.

ENMAX accepted the general principles of statutory interpretation as cited by EPGI. However, ENMAX argued that applying such principles to the GUR did not support EPGI's interpretation.

[190] Tr. p.5346-5347

In determining the scheme of section 44 of the GUR, specific sections must be read within the context of the whole. It was necessary to consider the entirety of "PART 5 GENERAL" of the GUR. In particular, sections 41 and 42 provide for the owner of a generating unit to "receive from the Balancing Pool the amount by which the costs of decommissioning the unit exceed the amount the owner has collected from customers, or through a PPA, for the purposes of decommissioning the unit."[191] As the Rossdale Units were deemed to be decommissioned at the end of 2000, and therefore become unregulated, section 42 would apply to the Rossdale Units. Sections 41 and 42 effectively deal with the issue of decommissioning cost, and the legislation assumes a portion of decommissioning costs may be recovered through the PPA process.

ENMAX continued that when the issue of parameters was considered in section 44, the net salvage cost parameter had already been dealt with in sections 41 and 42. It was, therefore, not necessary to deal with net salvage costs in sections 44(1) and 44(2), leaving only the issue of retirement dates. It was only in section 44(3), where the legislation was providing guidance for the determination of depreciation rates, that the concepts of decommissioning expenditures and retirement date come together. It was at this point that the use of the words retirement "date" in subsection 44(3)(a), and "parameter" in 44(3)(b) were necessary. Principles of statutory interpretation supported the position that the use of the word parameters is appropriate in section 44(3), and as such the Board must use the parameters established for the 1996 GTA. As indicated in Exhibit 41, the 1996 approved parameter for the Rossdale decommissioning was $17.2 million.

ENMAX noted that EPGI had stated on numerous occasions that it had not changed the depreciation parameters from those used in the 1996 GTA. ENMAX argued that the characterization of the extra decommissioning funds requested as a "reserve imbalance" was an attempt to escape the consequences of the GUR forbidding changes to the 1996 depreciation parameters.

Position of the FIRM Customers

The GUR is very clear as to the retirement dates for generating units. In particular, the GUR stipulates, in the event of a conflict between the regulation and the determination of the Board in Decision U97065, "the parameters established by the Board for the 1996 General Tariff Application" are to be applied in approving depreciation rates for 1999 and 2000. EPGI's proposal was inconsistent with those provisions and must be rejected.

Position of EPGI

EPGI argued that there was clearly no basis for ENMAX's and the FIRM Customers' assertions with respect to the effect of section 44 of the GUR.

[191] Section 41(2)(c), Generating Unit Regulation AR 72/99

Sullivan's text, *Driedger on the Construction of Statutes*, 3d ed.[192] summarized the modern rule of statutory interpretation as follows at page 131:

> ... courts are obliged to determine the meaning of legislation in its total context, having regard to the purpose of the legislation, the consequences of proposed interpretations, the presumptions and special rules of interpretation, as well as admissible external aids. In other words, the courts must consider and take into account all relevant and admissible indicators of legislative meaning. After taking these into account, the court must then adopt an interpretation that is appropriate. An appropriate interpretation is one that can be justified in terms of (a) its plausibility, that is, it compliance with the legislative text; (b) its efficacy, that is, its promotion of the legislative purpose; and (c) its acceptability, that is, the outcome is reasonable and just.

The Alberta Court of Appeal stated that the "modern rule of interpretation" consists of determining the object or scheme of the Act in question, and then giving the words used in the legislation the meaning that best advances that object or scheme, provided only that the actual words under review can "reasonably bear that interpretation."[193]

EPGI argued that in applying these principles of statutory interpretation to section 44 of the GUR, there could be little doubt that a court would construe the section as follows:

- Pursuant to sections 44(1) and (2) of the GUR, the Board must assume for the purposes of the 1999-2000 GTA filed by EPGI that Rossdale Units 8, 9 and 10 will be decommissioned on 31 December 2000. Mr. Stout confirmed during cross examination that this is the result of sections 44(1) and (2).[194]

- Pursuant to section 44(3) of the GUR, the Board is required to use the "parameters" established for the 1996 GTA in approving depreciation rates for 1999 and 2000 if (and only if) there is a conflict between the "parameters established by the Board for the 1996 GTA" and the dates referred to in sections 44(1) and (2), that is, a decommissioning date of 31 December 2000.

EPGI argued that section 44(3) indicates that the Board is only required to use the "parameters" established for the 1996 GTA in respect of EPGI's Rossdale Units if there is a "conflict" within the meaning of that section. If there is no such conflict, then the Board is not required to use the "parameters" established for the 1996 GTA. However, irrespective of whether there is or is not a

[192] Butterworths: Toronto, 1994

[193] *Jahnke v. Wylie* (1994), 26 Alta. L.R.(3d) 46 at 53, per Kerans J.A.; see also Cote, *The Interpretation of Legislation in Canada*, 2d. ed., (Yvons Blais: Cowansville, 1991), p.339

[194] Tr. p.5344

conflict within the meaning of section 44(3), the Board must assume that Rossdale Units 8, 9 and 10 are decommissioned on December 31, 2000 by virtue of sections 44(1) and (2).

EPGI continued that to construe section 44(3) as simply mandating that the Board is to use the "parameters" established for the 1996 GTA, whether or not there is a conflict as stipulated by section 44(3), would, in the words of the Alberta Court of Appeal, clearly be an interpretation which the words of section 44(3) cannot reasonably bear. Even Messrs. Stout and Kennedy confirmed in their response to EPGI/EPTI-ENMAXD-3(1) that section 44(3) is

> ...clear in the statement that if there is a conflict between the 'dates' (referred to in subsection (a)) and the 'parameters' (referred to in subsection (b)), that the Board must use the 'parameters' established in the 1996 General Tariff Application.

Any other interpretation of section 44(3) would clearly constitute an error of law reviewable on appeal.

Whether or not the Board is required to use the "parameters" established for the 1996 GTA therefore depends on whether a conflict exists within the meaning of section 44(3) of the GUR. This, in turn, depends on the meaning of "parameters" as that term is used in section 44(3).

In summary, Dr. White testified that as used in the context of a depreciation technical update, parameters include those descriptors of service life and net salvage that are independent of the age distribution of surviving plant and realized account activity relative to the study year (i.e. projection curves, projection lives, estimated year of final retirement for life-span categories, future net salvage rates and estimated net decommissioning costs), which are obtained from service life and net salvage studies.[195] The term "variable" was used to refer to those descriptors of service life and net salvage that are a function of the age distribution of surviving plant and realized account activity relative to the study year (i.e. average service lives, remaining lives and average net salvage rates).[196] Dr. White testified that parameters used by EPGI are retained in a technical update and depreciation rates are adjusted for known and measurable changes in the age distribution of surviving plant, depreciation reserves and average net salvage rates attributable to the passage of time.[197]

Messrs. Stout and Kennedy did not provide an exhaustive list of what they would consider to be parameters, but they indicated their view that estimated total decommissioning costs and remaining life estimates are parameters.[198] Mr. Pous stated that he is not aware of a definition of parameters "specifically for depreciation purposes," and relied upon the Random House

[195] Exhibit 175, p.2, l.25-p.3, l.2; Tr. p.1337; 1999 and 2000 Technical Updates, p.5
[196] Exhibit 175, p.3, l.3-6
[197] Exhibit 175, p.3, l.9-12
[198] Exhibit 173, p.1, l.28-p.2, l.4

Dictionary as a basis for asserting that essentially all of the components of a remaining life accrual calculation are "parameters." Mr. Pous loosely referred to these components as original cost, net salvage, life, remaining life, actual reserve and theoretical reserve.

EPGI noted that Mr. Pous' "all inclusive" definition of the word "parameters" would effectively preclude the Board from adjusting depreciation rates in 1999 and 2000. EPGI argued that this clearly could not be the intention of the GUR and was contradictory to Mr. Pous' testimony during cross examination that section 44 of the GUR does not preclude the Board from adjusting depreciation rates.

EPGI noted that although it had not changed any "parameters" within the meaning of that term in section 44(3), in the case of EPGI's Rossdale units it was unnecessary to make any distinction between what is or is not a "parameter" within the meaning of section 44(3). Even if one were to accept the "all-inclusive" meaning of the word "parameter" proffered by Mr. Pous, the only conclusion that could be reached was that no conflict existed within the meaning of section 44(3) of the GUR and, accordingly, that the Board was not bound to use the "parameters" established for the 1996 GTA in approving depreciation rates for 1999 and 2000.

During cross examination, Mr. Stout confirmed that there is no conflict between each of the estimated year of final retirement for life span categories, the estimated net salvage decommissioning costs, the plant original cost and the recorded reserve as established by the Board for the 1996 GTA and a decommissioning date for the Rossdale units of 31 December 2000. The average service life (referred to by Mr. Pous as "life") and average remaining life (referred to by Mr. Pous as "remaining life") components of the formulas established by the Board for the 1996 GTA were based on a 31 December 2000 decommissioning date.[199] Although it was not necessary to calculate a theoretical reserve for the purposes of determining EPGI's depreciation expense in the 1996 GTA, a theoretical reserve could be derived. As the components which make up the calculation of the theoretical reserve (i.e. "net salvage", "life" and "remaining life") were not in conflict with a decommissioning date of 31 December 2000, it follows that the theoretical reserve would not be in conflict either.

EPGI concluded that it was therefore clear that there was no conflict between the items listed above and a decommissioning date of 31 December 2000. Having determined that there was no conflict within the meaning of section 44(3), it is open to the Board to determine appropriate "parameters" for the purposes of determining depreciation rates for EPGI's Rossdale units for 1999 and 2000, subject to the requirement in sections 44(1) and (2) that the Board assume a date of decommissioning for each unit of 31 December 2000.

EPGI argued that many of the assertions of ENMAX and the FIRM Customers were based on the untenable position that the Board's discretion is fettered by section 44(3) such that the Board

[199] Schedule A, 1995 EEMA Forecast Filing

must use the "parameters" established for the 1996 GTA.[200] ENMAX and the FIRM Customers were effectively arguing that the Board is restricted from approving "parameters" for EPGI's Rossdale units in 1999 and 2000 which were reasonable having regard to the relevant circumstances surrounding the Rossdale units. Assertions which have as their basis the proposition that EPGI was bound by the GUR to use the "parameters" established for the 1996 GTA should be rejected by the Board as being clearly without any basis in law and, therefore, irrelevant.

EPGI argued that it had not changed any "parameters" within the meaning of section 44(3) of the GUR. However, even if it could be concluded that EPGI had changed "parameters", it was clear that the issue to be determined by the Board was not whether EPGI's applied-for depreciation expense reflects a change of "parameters," but instead whether the costs that make up EPGI's applied-for depreciation expense were prudent.

EPGI countered the ENMAX claim that the fact that TransAlta had revised its Application to reflect depreciation rates approved in 1996 once the GUR came into force in March 1999 supported the claim that EPGI should have revised its Application. There was no basis for the suggestion that the fact that TransAlta had chosen to revise its Application indicated that EPGI should also have revised its Application. There was also no basis for the suggestion that because EPGI's Application was filed before the GUR was issued, that Application must necessarily be inconsistent with GUR. EPGI noted that the comments of TransAlta in section 7.0 of Exhibit 60 which indicated that TransAlta saw no need to vary its depreciation rates from those approved in 1996.

EPGI noted that ENMAX had asserted that the recovery of actual and tendered cost for decommissioning work in excess of the amounts forecast for this work was prohibited by section 44 (3) of the GUR. EPGI argued that Section 44 (2) clearly refers only to a date of decommissioning, not to any other "parameter". EPGI agreed with the characterization made by LE/RD that this section deals only with projected life parameters. Further, EPGI noted that even with the broadest possible interpretation of the GUR there was no "conflict" between the EPGI Application and GUR.

Board Findings

The Board notes that the overall intention of section 44 of the GUR is clearly to guide the Board in establishing the allowed depreciation expense for regulated generating units for the 1999/2000 test period. Section 44(3) establishes that if there is a conflict between the date specified in the GUR and what has previously been found by the Board for the 1996 GTA, the Board is to maintain the dates established in its previous decision. Logically, the only "parameters" which may be in conflict with a date are other dates or items which are directly consequential to dates, such as the service life calculated from dates and used in depreciation calculations. The Board is

[200] See for example Exhibit 42, p.8, l.22-p.11, l.2; Exhibit 41, p.4-6, p.7-9; Tr. p.5361-5362

unaware of any conflicts between the dates specified in sections 44(1) and 44(2) and the dates used in the 1996 GTA.

Therefore, the Board considers that section 44(3) of the GUR clearly requires the Board to continue to use the year of final retirement dates determined in the 1996 GTA in fixing depreciation expense for 1999 and 2000. However, it is less clear whether the Board is required to continue to use the gross salvage and cost of removal parameters determined in the 1996 GTA in fixing depreciation expense for 1999 and 2000 when there is no conflict in the dates. The Board notes that it would normally not review gross salvage and cost of removal parameters independently of a review of years of final retirement. Therefore, that is the general principle the Board will follow in determining 1999 and 2000 depreciation expense. The Board considers, however, that an exception to this general principle is warranted when a generating unit is expected to retire during or very close to the test years. The Board considers, in this instance, it is important that estimates of gross salvage and cost of removal (i.e. decommissioning costs) be updated to ensure that intergenerational equity is maintained.

Accordingly, the Board finds that section 44(2) of the GUR compels the Board to continue with the assumption that the Rossdale 8, 9 and 10 generating units are to be decommissioned as of 31 December 2000 as previously approved in the 1996 GTA.

The Board notes the argument of ENMAX with regards to section 42 of the GUR that clearly envisions the recovery of certain decommissioning costs under the PPA regime. Although the Board does not agree with the extension of that argument to restrict the Board's ability to fairly adjust depreciation rates to recover prudent decommissioning expenses up to 31 December 2000, the Board does find that it is not constrained by the GUR to the recovery of all actual and forecast Rossdale decommissioning costs in the 1999/2000 test period.

(B) Effect of the GUR on the Mid-Year Depreciation Convention

Position of the FIRM Customers

The FIRM Customers noted that the retirement date for the Rossdale plant set out in 1996 GTA was the end of 2000, not the middle of 2000 as proposed by EPGI. This was a violation of the GUR. They argued that EPGI's adherence to their position on this matter should cast doubt on the credibility of EPGI's other assertions.

Position of ENMAX

ENMAX considered the use of the mid-year convention as the basis for a 1.5 year remaining life as of 31 December 1998 for the Rossdale Generating Plant, as proposed, to be a revision to the life parameter as approved in Decision U97065. In 1996 Edmonton Power showed the remaining life of the Rossdale plant as 7.0 years as of 31 December 1993.[201] Had they employed

[201] Exhibit 126, 1996 GTA

the mid-year convention, this would have been 6.5 years. Dr. White switched to the 1.5 year remaining life in his Technical Update.

ENMAX argued that the modification of the retirement date from 31 December 2000 as approved by the Board, as proposed by EPGI, violated section 44 of the GUR. Section 44(2) listed Rossdale Units #8, #9, and #10 to have a retirement year of 2000. This section also stipulated that "the Board must assume that the [following] regulated generating units is decommissioned on the last day of the year shown for that unit." If the Board approved a date other than the date established by the GUR, this would be in violation of the regulation.

ENMAX noted that EPGI had reaffirmed use of the December 31st, 2000 retirement date for the Rossdale units. In response to MI.EPGI.10, EPGI indicated that "EPGI [had] prepared its 1999/2000 GTA on the premise that each of the Rossdale units will retire and be physically decommissioned at the end of 2000 which is the year of final retirement approved by the Board."

In as much as EPGI forecasted no interim retirements and the date of final retirement must be assumed to be 31 December 2000, ENMAX argued that there existed no reasonable argument for use of a remaining life of less than two years. Use of the mid-year convention in this circumstance was not appropriate.

ENMAX noted that EPGI had become indifferent with respect to the timing of the recovery of the decommissioning reserve. Therefore, ENMAX requested that the Board approve a 2-year remaining life for the Rossdale units as of 31 December 1998.

Position of EPGI

While EPGI was of the view that the use of the half-year convention for Rossdale was reasonable and appropriate for the reasons provided by Dr. White whether or not the half-year convention is used is really a "non-issue" as it relates only to the timing of recovery.[202] All of the depreciation witnesses agreed. The effect of adopting a full-year convention for Rossdale is that $2.808 million in depreciation expense for Rossdale would be shifted from 1999 to 2000.[203] As Dr. White stated, "It is largely immaterial ... which convention is adopted, provided revenue is sufficient to recover the allowed expense."[204]

EPGI noted that Section 44 (2) of the GUR speaks only of the date of decommissioning. The only requirement in that section is that the Board assumes a date of decommissioning of 31 December 2000 for the Rossdale units. The use of the half-year convention for Rossdale, which assumes retirement in mid-2000, is clearly consistent with a date of decommissioning of 31 December 2000.

---

[202] Tr. p.5382
[203] Exhibit 175, p.7, l.8-13
[204] EPGI Argument, p.5-17

Board Findings

The Board finds that, as stated by the EPGI witness, the allocation period of any decommissioning reserve imbalance is "largely immaterial.. provided revenue is sufficient to recover the allowed expense." The Board notes that the mid-year convention is a notional method for smoothing year-to-year variations in capital cost recovery as assets are added and retired. This convention assists in providing for rate stability over the life of the assets. The Board finds, in this situation of a large final retirement, that rate stability would be assisted by allocating an equal amount of allowed decommissioning costs to 1999 and 2000. Accordingly, the Board directs EPGI, in its refiling, to allocate an equal amount of the allowed decommissioning costs to 1999 and 2000.

(C) Prudence of Applied For Cost Increases

The amount of the decommissioning reserve for Rossdale was previously established in Decision U97065 on the basis of a study by Monenco Agra Engineering. That study established total decommissioning costs for the Rossdale plant to be $17.186 million. EPGI requested that the decommissioning reserve for Rossdale be increased to $30.903 million based on actual work undertaken to date and work tendered for 1999. The variance between the previously approved amount and the 1999/2000 Application was summarized as follows:

	$ Millions		
	Monenco Forecast	**Cost Variance**	**Total**
Work completed 1996-1998			
-Asbestos Removal	$1.613	$0.470	$2.083
-LP Plant Equipment Removal	1.714	3.765	5.479
Work to be completed in 1999			
-Asbestos Removal	0.898	(0.05)	0.848
-LP Plant Services Relocation	--	3.180	3.180
-LP Land Demolition	1.598	6.352	7.950
Work to be done at final retirement			
-Asbestos Removal	1.102	--	1.102
-HP Plant Equipment Removal	1.427	--	1.427
-Building/Common Facilities Demolition	8.834	--	8.834
Total	$17.186	$13.717	$30.903

Source: ENMAX-EPGI-57

EPGI submitted that the low-pressure Rossdale plant was to be demolished prior to 2001 with the relocation of infrastructure and space from the low-pressure plant to the high-pressure plant at Rossdale. The purpose of this was to enable the continued operation of the high-pressure Rossdale Units 8, 9, and 10 into the future. A new unregulated unit, Rossdale Unit 11, was to be added with steam from that plant to be used to repower Rossdale Unit 8.

Position of the FIRM Customers

The FIRM Customers noted that the majority of the increase in depreciation expense in this case was attributable to the imbalance in the accumulated provision for depreciation associated with the Rossdale plant. This imbalance was a function of actual expenditures made by EPGI as well as future expected expenditures. The expenditures potentially related not only to prudent and necessary costs associated with the dismantling of regulated facilities but may also contain costs associated with the planning and construction of Rossdale Unit 11, a non-regulated portion of EPGI's business. The burden of proof associated with establishing the reasonableness of such transactions must be greater than for arms-length transactions. Unless proven otherwise, affiliate transactions should be considered as inappropriate.

The FIRM Customers argued that the concept of affiliate transactions and the need to substantiate the reasonableness of such expenditures should not have been new to EPGI. In EEMA Decision E92111, the Board directed Edmonton Power to provide a detailed description of the services provided by the City of Edmonton. The Board summarized its position by directing the City of Edmonton "...to verify that the agreements are similar to arrangements that could be negotiated in the marketplace by parties acting reasonably and at arms length."

EPGI did not provide detailed descriptions of the expenditures or valuation of the reasonableness of the expenditures for the activities at Rossdale. It chose an entirely different manner of justifying the increase in demolition costs than presented in the last case. By presenting information via a technical update, the FIRM Customers argued that EPGI did not meet the burden of proof. Even if the expenditures were not associated with affiliate transactions, this would still have been the case. Therefore, the Board must disallow the proposed increase in Rossdale decommissioning costs.

The FIRM Customers criticized the credibility of the information being provided by EPGI. They noted that Dr. Bridgeman, in response to questions from Mr. Berg concerning the allocation of cost between the demolition of the regulated units and construction of the non-regulated unit, stated that EPGI was very mindful of cost allocations associated with relocation of services. However he qualified this assurance, stating it was "a matter of perspective." The Board and customers were left with only EPGI's statements that it believed its approach was fair. The FIRM Customers stated that customers and the Board were entitled to more substantial proof.

As related in the evidence of Mr. Pous, when a utility wears two hats, as EPGI did in this instance, additional checks and balances must be established to protect the rights of ratepayers. The FIRM Customers argued that the degree of supporting information provided by EPGI in this

proceeding was woefully lacking. Possibly one of the most disturbing aspects of EPGI's presentation was its acknowledgement of changes or potential changes to its application when limited probing of its figures was undertaken.

EPGI admitted approximately $1.6 million of its proposed demolition costs at Rossdale could be eliminated if the demolition of all units occur at one time. It also noted a $4.3 million reduction under a notional plan for decommissioning prepared in response to an undertaking for Mr. Berg.[205] EPGI admitted the decommissioning cost estimate for Rossdale should be reduced for certain types of work already completed and included in the original $17.2 million cost estimate. EPGI had more than adequate opportunity to present substantial additional data to support its position. Instead, it chose to present only minimal, summary information, without any support for its change in position.

The FIRM Customers noted that Dr. White, EPGI's witness in support of the appropriateness of the reserve imbalance and the recovery of such costs, was totally unfamiliar with the details underlying the imbalance. He was not familiar with the underlying analysis from 1996 and could not testify to the validity of any of the numbers comprising the reserve imbalance. Yet, he believed it was appropriate for EPGI to recover this amount from customers. Dr. White's evidence also suffered from inconsistent application of terminology. He seemed to admit error only when "caught." An applicant cannot, and should not, expect to reasonably meet its burden of proof if it presents minimal information and questionable data that are only corrected when a party is able to ferret out a problem.

EPGI proposed to establish a basis for recovery of its depreciation expense through a technical update rather than a traditional depreciation study. It simply accepted a knowingly incorrect decommissioning value of $17.2 million for Rossdale with the intent of recovering all estimated and actual amounts through reserve imbalance amortization. EPGI was well aware that this proceeding was the last regulated rate case for electric generation investment. As there was no attempt to develop a more accurate and current net salvage study, the record was entirely devoid of detailed information regarding specific reasons for each of the cost variances. Nor was there any evidence to demonstrate whether or not the allocation of such cost to regulated customers was appropriate. If EPGI's approach were adopted, the Board and ratepayers would be denied the right of having a reasonable opportunity to test the accuracy of EPGI's presentation. The FIRM Customers also argued that the use of a technical update rather than a full depreciation study afforded EPGI to freely allow Dr. White any modifications or inconsistent treatments he might deem appropriate in developing the depreciation rates.

The FIRM Customers also noted that EPGI had ignored the Board's long and consistent practice of limiting the amortization of reserve imbalances to situations where the imbalance exceeds a 5% threshold. EPGI chose to ignore this practice resulting in another increase in depreciation

[205] Exhibit 57

expense of approximately $250,000 annually. The FIRM Customers submitted that there was no evidence to support a change in the Board's practice in this case.

In reply argument the FIRM Customers reiterated that the record should lead to the conclusion that EPGI's depreciation request was neither reasonable nor appropriate. Customers and the Board were entitled to a fair and reasonable review of what were substantial increases in decommissioning costs. This was especially true given a long history of EPGI's inability to accurately predict and present depreciation information, even when directed to do so over 16 years ago.

The FIRM Customers stated that EPGI was clearly in error when it stated that depreciation expense calculations were based on previously approved studies. The record indicated that $17.2 million was approved for the decommissioning expense for the Rossdale plant. There was no new study in this proceeding addressing the new $30.9 million decommissioning cost requested by EPGI.

The FIRM Customers noted that EPGI had claimed the proposed depreciation parameters were previously approved. This may have been based on EPGI's statements that there are no firm rules associated with a technical update of depreciation costs. There was no evidence on the record that the superficial decommissioning cost summary presented, in fact, contained only prudent costs. The FIRM Customers argued that the record did demonstrate that the newly claimed decommissioning costs arose from affiliate transactions. The Board and customers could not accept EPGI's claim that it showed "adequate steps where necessary to update information to ensure accuracy and reasonableness."

The FIRM Customers argued that EPGI was attempting to shift the burden of proof to customers. EPGI failed to prove the decommissioning costs were reasonable and prudent. The FIRM Customers noted that EPGI had stated "cost proved to be far higher" than anticipated "due in part" to EPGI's inability to realize a certain level of net salvage. EPGI failed to note in its argument it was able to sell turbine/generator #3 at Rossdale and part of the turbine/generator #4 for $259,000. Nor did EPGI make mention of the fact that it did not have to incur over $230,000 of additional demolition costs due to the sale.[206] EPGI chose to overlook the omission of this in the Monenco Agra study. The FIRM Customers argued that it was this lack of full disclosure on the part of EPGI which demanded a complete review of actual costs prior to the granting of EPGI's requested decommissioning reserve.

The FIRM Customers noted that EPGI stated "it always intended to decommission the LP plant prior to the decommissioning of the High Pressure plant." Yet, it stated that the Monenco Agra study assumed the units would be retired simultaneously. The FIRM Customers noted that this appeared to be admission that EPGI knowingly provided the Board and Intervenors with false information in the last proceeding.

[206] FIRM.EPGI I-19

The FIRM Customers submitted that EPGI did not present adequate evidence to substantiate its cost allocation between its regulated and non-regulated businesses pertaining to the demolition of the Rossdale plant. Without detailed and complete proof of the appropriateness of these transactions, the proposed allocation must be presumed to be inappropriate. The FIRM Customers requested that the Board reject EPGI' figures and retain the depreciation rates established in Decision U97065.

Position of ENMAX

ENMAX submitted that the net salvage requested by EPGI had not been adequately justified. In contrast to TransAlta, which had decided to revise its application and revert to the depreciation rates approved in Decision U97065, EPGI chose not to alter its application in response to the GUR of 15 March 1999. EPGI suggested that their technical update conformed to a very strict interpretation of the regulation.

In 1996, the Board approved an amount of $17.186 million for the final demolition of all units at the Rossdale generating plant. This estimate was established as the parameter for "future net salvage" costs, even though many of the facilities to be dismantled and funded with this money had been retired for a number of years. This fund was never intended to fund only the decommissioning expense from "future" requirements of the plant. It was established to fund all Rossdale Plant decommissioning expenditures from 1996 forward.

From 1996 to the end of 1998, EPGI expended $7.562 million for the final decommissioning of Rossdale facilities. These expenditures were clearly part of the funding contemplated by the Board in its approval of the $17.186 million. It became clear that the $30.903 million was an updated estimate of the same specific functions established by the Board in U97065. This must be considered a revision to the 1996 depreciation parameters.

EPGI suggested that of the $7.562 million expended from 1996 through 1998, only $3.327 million of this amount should be removed from the original cost estimate of $17.186 million, with the remainder to be recovered in 1999 and 2000. EPGI stated that only the smaller amount was included in the original budget for the activities carried out during that time period. EPGI made the same claim for the $11.978 million 1999 expenditure that was only budgeted for $2.496 million in 1996. EPGI suggested that the total $17.186 million decommissioning budget be reduced by only $5.823 representing the budgeted activities that had been completed, regardless of the actual expended amount. ENMAX argued that notwithstanding the fact that any change in net salvage parameters would be in violation of the GUR, it noted that EPGI had never come forward asking for approval of the additional expenditures. In response to FIRM.EPGI.02, EPGI stated that "an update of the demolition cost estimate [had] not been performed." This statement was made at a time when EPGI must clearly had known that they would overspend the 1996 Rossdale decommissioning estimate.

Instead of the extensive engineering reports provided and defended at the 1996 GTA., EPGI provided only the extremely limited cost information contained in ENMAX.EPGI-57. EPGI entered no detailed evidence to revise the original Rossdale decommissioning estimate by component. EPGI did not provide reasons to justify the variances between the estimates and actuals. ENMAX express concern that if over-recovery of this expense is allowed with no detailed review, the budgeted expenditures for 1999 may also reach cost over-runs of a similar magnitude. ENMAX submitted that the Board should not burden customers with this unsupported cost increase.

In reply argument, ENMAX noted that contrary to the evidence of EPGI that it had provided detailed information with regards to the increased in total decommissioning costs, the initial responses to information requests denied a change in the estimate of decommissioning costs. It was not until 30 March 1999 that EPGI produced a spreadsheet that showed a difference of $13.7 million between the originally estimated and actual cost of decommissioning. ENMAX argued that EPGI had not provided any support for this difference.

Position of LE/RD

LE/RD submitted that a change in decommissioning cost from approximately $17 million to $31 million in a period of two years required more than a technical update which calculated reserve imbalances. The study upon which the 1996 calculation of future net salvage for the Rossdale units had not been updated. No detailed information had been presented in support of the EPGI proposal to justify the significant increase in decommissioning expense. It was clear that some of the costs arose because the Rossdale units will continue to function after the decommissioning of the low pressure plant and because EPGI proposed to install Rossdale 11, requiring demolition of the LP plant in 1999. LE/RD submitted that these costs, which may total some $4.7 million, should not be the responsibility of customers in the test years 1999 and 2000. Because EPGI had not filed any updated demolition cost information to explain the dramatic increase in decommissioning costs, LE/RD argued that those increase costs should be viewed with a degree of skepticism.

In reply argument, LE/RD submitted that the Board should view the increase costs associated with decommissioning the Rossdale plant with considerable care in all circumstances. LE/RD noted that EPGI had not provided an update to the previous study establishing the original depreciation allowance. Nor did it provide additional assurance that the remaining forecast reserve remained reasonable.

EPGI had noted that it should not be faced with the prospect of sterilization of its land for other uses. This evidence ignored the fact that the reason for the decommissioning of the low pressure plant in advance of the high-pressure plant was to support the installation of a non-regulated unit which may use infrastructure paid for by the consumers and for which they will receive no credit even though entitled to such a credit based on the policy determination of the government.

As a result of the desire of EPGI to install an unregulated generating unit on the Rossdale site and the extension of operation of the other Rossdale units, extra costs had been incurred arising from the separate decommissioning of the low pressure plant. LE/RD argued that it would not likely be a prudent expenditure to spend hundreds of thousands of dollars extra instead of waiting to decommission the two plants after the retirement date 31 December 2000. Nor would this expenditure be fair and reasonable to be charged to customers. LE/RD submitted that EPGI cannot have at both ways: the cost for the 1999/2000 customers are recovered based on the units retiring as of 31 December 2000, but customers were also being asked to bear increased costs of decommissioning because the plants will operate beyond that date.

Position of EPGI

EPGI countered the ENMAX claim that it had revised its estimate of total decommissioning costs for Rossdale to 180% of that approved by the Board in 1996. EPGI noted that during cross-examination, Mr. Stout and Mr. Kennedy confirmed that in the absence of section 44 of the GUR, they had only two concerns with respect to the Rossdale decommissioning costs. First they were of the view that EPGI must satisfy the Board as to the reasonableness of cost differences and second they suggested that costs over and above those forecast should be reflected commencing in 1999 rather than in 2000.

EPGI also countered the FIRM Customers accusation that EPGI had attempted to "mask" the increases in decommissioning costs for Rossdale. EPGI noted that it had provided substantial evidence which clearly identified the increase in decommissioning costs and demonstrated the prudence of those costs. The increases were described in the Application, in Attachment 3 to Exhibit 8 (filed with the Board on 22 March 1999) and in response to information requests. Further, Dr. Bridgeman and Mr. Topping provided further explanation respecting the breakdown of Rossdale decommissioning costs.

During cross-examination regarding the $3.180 million shown as "LP Plant Services Relocation." Mr. Topping testified that approximately $1.6 million of the cost is in respect of equipment that must be installed in 1999 to allow for the continued operation of the HP Plant, including compressed instrument and air services, water lines, 15 kV switchgear, the 480 volt motor control centre. The remainder of the cost is in respect of removing the equipment which would occur in the decommissioning process.[207] Dr. Bridgeman responded to the suggestion that a certain portion of these costs could be deferred until the final decommissioning of the HP Plant:

> A DR. BRIDGEMAN: Mr. Bryan, while Mr. Topping is looking, providing that number, the concept of defer would simply mean that that piece of property would effectively be sterilized and unusable.

[207] Tr. p.1322

So just for the record and so the Board understands, we see this as really the decommissioning of the LP plant, and as part of that decommissioning, there are some lines, services running through that piece of property to service the HP plant. So as we decommission, we are removing the buildings and the equipment. We also see a need, though, to move those services to provide for the continued operation of the HP plant, and to suggest that that would be deferred would effectively sterilize that property, and we don't believe that is appropriate or fair.

We believe that the LP plant needs to be decommissioned and removed, and that is what we are undertaking to do. If that HP plant kept going for another 20 years, that would suggest that that piece of property effectively would be sterilized for 20 years, and it was a savings to customer back at the time to route those services through the LP plant, but nevertheless, now it is encumbering that property. So we think it is appropriate that we do that work. [208]

EPGI noted that with respect to the reasons for the cost variances from the Monenco forecast decommissioning costs identified in column C of the table included in ENMAX-EPGI-57(1), Dr. Bridgeman and Mr. Topping testified as follows:

- Certain of Monenco cost estimates have proven to be too low in light of actual and tendered costs. For example:

- The work completed to the end of 1998 is the same scope of work contemplated in the Monenco Study, but the costs proved to be far higher. This was due in part to EPGI's inability to realize some $1.3 million in salvage value for LP plant process equipment anticipated in the Monenco study, despite having taken an extra two years in attempting to sell the equipment.

- The tender for the building demolition costs (shown on line 6 of the table) has proven to be $1.7 million higher than the Monenco estimate, likely because the demolition contractors can determine the scope of work more clearly with the plant equipment having been removed.

- As well, there are additional costs being incurred due to the assumption in the Monenco study that the LP and HP plants would be decommissioned simultaneously. At the time that the Monenco study was completed in 1995, EPGI had obtained Order HE9308 directing that the Rossdale Low Pressure plant be decommissioned. In accordance with the Order, EPGI had always intended to decommission the LP plant prior to the decommissioning of the High Pressure plant. However, the Monenco study assumed that the two

[208] Tr. p.1320

> plants would be decommissioned simultaneously. For example, with the decommissioning of the plants occurring at different times, there is a need to move existing services in order to decommission the LP plant that were not anticipated in the Monenco study. [209]

EPGI argued that neither ENMAX nor the FIRM Customers led any substantive evidence to demonstrate that the decommissioning costs incurred and estimated future decommissioning costs for Rossdale were not in accordance with the Monenco study. EPGI noted that the witnesses for the FIRM Customers and ENMAX appeared to be unfamiliar with the information provided by EPGI.

EPGI argued that the evidence clearly demonstrated that the increase in decommissioning costs over the previously approved Monenco estimate of $17.186 million was reasonable and prudent and should be approved by the Board. The cost variances were based, not on forecasts, but on actual decommissioning experience gained by EPGI since the 1996 GTA. The decommissioning costs of $7.562 million relating to work completed during 1996 to 1998 have actually been incurred. The work which formed the basis for the $9.482 million in decommissioning costs in 1999 had been commenced and was to be completed during 1999. The amount of $11.363 million for final decommissioning work was the cost that Monenco forecast for that work and was as approved in the 1996 GTA.

In his rebuttal evidence, Dr. White demonstrated both algebraically[210] and in tabular form[211] that differences between the Monenco estimated costs and actual expenditures during 1996, 1997 and 1998 create a reserve imbalance that EPGI had properly included in its formulation of a remaining-life depreciation accrual. ENMAX, on the other hand, reduced the reserve imbalance (thereby reducing depreciation expense) by deducting $7.562 million of decommissioning work completed over the period 1996-1998 from the Monenco estimate of $17.186 million. EPGI argued that this adjustment erroneously assumed that the cost of all decommissioning work completed by EPGI was contemplated in the Monenco estimated costs. EPGI properly reduced the Monenco estimate by $3.327 million of pre-1999 decommissioning work completed and included in the prior Board-approved estimate of $17.186 million. The remaining $4.235 million ($7.562 million - $3.327 million) represented a reserve imbalance that EPGI properly amortized over the years 1999 and 2000.

EPGI argued that the FIRM Customers did not reduce the $17.186 million parameter by the cost of decommissioning work completed over the period 1996-1998. The FIRM Customers achieved an identical result by restating (i.e., increasing) EPGI's recorded reserve by the cost of decommissioning work completed.

---

[209] Tr. p.1323-24 and 1359f
[210] Exhibit 175, p.10-11
[211] Attachment 2

2. EPGI
(d) Depreciation

EPGI argued that the FIRM Customers' attempt to portray EPGI's treatment of the reserve imbalance as a "word game" was absurd. EPGI argued that, knowing full-well the origin and magnitude of the reserve imbalance, the FIRM Customers nevertheless claims that

> ... one has to delve deeply into the game of semantics [to understand] how EPGI can be seeking approximately $31 million for decommissioning Rossdale yet at the same time claim it is in compliance with the $17.2 million parameter reflected in the 1996 GTA.[212]

The cause and proper treatment of the reserve imbalance was clearly explained by Dr. White:[213]

> Both ENMAX and the FIRM Group refuse to acknowledge that the cost of decommissioning work completed (and not contemplated in the Board approved estimate of $17.186 million) creates a depreciation reserve imbalance that EPGI has properly included in its formulation of a remaining-life depreciation accrual The reserve imbalance is caused by accruals insufficient to recover the cost of decommissioning work completed. Stated differently, it is the difference between actual (*i.e.*, incurred) and forecasted decommissioning costs that has created the reserve imbalance. The forecast of $17.186 million has not been changed.

During examination of the ENMAX and FIRM Customers panels, the Chairman referred to EPGI's response to an undertaking given to Mr. Berg at p.1487-1489,[214] and suggested that one approach to Rossdale decommissioning costs may be to reduce those costs by some portion of the difference between the applied-for $12 million amount and the "notional" $7.3 million amount shown on line 8 of the table in that response. The Chairman indicated that the amount of the reduction could then be loaded onto the cost of the new unit as being related to the high pressure plant.

When asked by the Chairman if he saw any rationale for such an approach, Mr. Stout declined to agree that those decommissioning expenses be loaded onto Rossdale 11 in stating:[215]

> I don't know that I would go so far as to suggest that it [i.e. the cost difference] is related to the new unit, but I do think you could interpret that to be related to the continued operation of Units 8 through 10.

While Mr. Pous questioned whether some portion of EPGI's decommissioning costs may have arisen as a result of the proposed Unit 11, he provided no substantive evidence to suggest that this is in fact the case.[216]

---

[212] FIRM Customers Evidence, p.9, l.8-13
[213] Exhibit 175, p.12, l.14-21
[214] Exhibit 57
[215] Tr. p.5380

Dr. White expressed his concern respecting this issue[217] that shifting costs related to capital committed to assets in a regulated environment (i.e. the GTA world) into the PPA world may not be consistent with the objectives of the PPA world. The opportunity of collecting costs related to the dismantlement of assets whose capital was committed in a regulated environment should fall within the regulated environment. Dr. White expressed concern as to whether the PPAs would sell if the costs were shifted into the PPA world.

The Chairman also asked whether, assuming there were no GUR, one approach may be to split the total $30.9 million decommissioning cost into LP plant and HP plant components, and allow full recovery of the LP plant portion with the HP plant portion being collected over the life extension period under the PPAs. In response to this suggestion, EPGI notes that sections 44(1) and (2) are clear that for the purposes of the 1999/2000 GTA, the Board must assume that Rossdale Units 8, 9 and 10 are decommissioned on 31 December 2000. The requirement to make this assumption precludes the Board from amortizing decommissioning costs relating to Rossdale Units 8, 9 and 10 past 31 December 2000.

EPGI countered the FIRM Customers argument that it had ignored a long-standing "5% reserve amortization threshold" in developing its depreciation proposal for this Application. EPGI argued that there was clearly no legal or regulatory requirement which mandated such a threshold. At most, the threshold was a practice that had arisen in this jurisdiction and, as such, its appropriateness must be examined by the Board based on the particular facts of each case. The FIRM Customers provided no substantive basis for imposing the 5% threshold in respect of EPGI in this case.

In reply argument, EPGI countered the ENMAX assertion that EPGI had changed the $17.186 million forecast amount approved by the Board in Decision U97065 for decommissioning of the Rossdale plant. EPGI noted the decommissioning reserve imbalance was caused by the difference between the estimated costs and the actual expenditures or decommissioning work completed during 1996, 1997, and 1998. Differences between the estimated costs and actual expenditures for work commenced in 1999 were based on actual and tendered costs. Costs for work to be completed at final decommissioning of the Rossdale plant were based solely on the amounts forecast for this work and will be recovered by the end of 2000 in the normal course.

EPGI countered the ENMAX accusations, that it was not prepared to justify cost variances, as mere conjecture, having no basis in evidence or regulatory requirements. There was no requirement that EPGI needed to come forward for special "approval" of its Rossdale decommissioning costs. Section 52 (1) of the EU Act provides that in consideration of an application under Section 49, the Board shall have regard for the principle that a tariff must provide the owner of an electric utility with the reasonable opportunity to recover the prudent

[216] Tr. p.5411-5412
[217] Tr. p.5523f

costs associated with capital related to the owner's investment in the electric utility, including depreciation. If the Board determines that the components of the depreciation expense are prudent, they must be approved.

EPGI argued that the Intervenors had failed to lead any substantive evidence to demonstrate that the decommissioning cost for Rossdale of $19.6 million to be incurred by the end of 1999 and the $11.363 million for final decommissioning work was unreasonable or imprudent. EPGI noted that none of the Intervenors felt the need to follow-up for further details respecting these costs either in respect of EPGI's responses to information requests or through cross examination.

EPGI countered the FIRM Customers argument that its presentation was "confusing" or "clouded" the issues surrounding depreciation expense. EPGI asserted that the FIRM Customers provided no analysis or substantiation for its assertions. EPGI also countered the FIRM Customers argument that if the depreciation expense was accepted as applied for, "the Board and rate payers will be denied the right of having a reasonable opportunity to test the accuracy of EPGI's presentation." EPGI noted that the FIRM Customers apparently saw no need for further details respecting its approach to depreciation costs. EPGI noted that in response to FIRMD-EPGI-19, the FIRM Customers was provided with copy of EPGI's demolition contract with McCollum & Sons respecting the LP plant equipment removal during the period 1996 to 1998. This contract related to work which was forecast to cost $1.7 million but proved to actually cost $5.5 million.

EPGI argued that the FIRM Customers had unfairly criticized the various parties involved in determining EPGI's depreciation expense over the years, including both the Board and EPGI. The record demonstrates that the Board has consistently discharged its mandate to approve fair and reasonable depreciation expenses for EPGI.

Board Findings

The Board shares the concerns of the Intervenors that decommissioning costs for the Rossdale plant have escalated alarmingly since the 1996 GTA. The Board is concerned that EPGI does not recognize that some of these decommissioning costs may be more properly associated with either new non-regulated units or the life extension of existing regulated units. There should be some recognition by EPGI of the potential conflict between regulated and non-regulated activities and processes should be in place to deal with such conflicts.

The depreciation reserve was established to record, over time, the actual and estimated costs of decommissioning the Rossdale generating station. Where it is clear that the cost estimates were inaccurately low, the Board finds that it is reasonable and fair to adjust the decommissioning reserve recovery amounts to collect the discrepancy between the estimated and actual amounts, provided the actual expenditures are prudent.

However, the Board does not find that all of the costs requested to be recovered during 1999 and 2000 for Rossdale decommissioning reasonably relate to the plant's provision of service during

that period or to the requirements of the EU Act and/or the GUR. EPGI has acknowledged that some of the costs requested for recovery via the decommissioning reserve relate to the ongoing operations of the Rossdale high pressure plant and possibly to the associated, non-regulated Rossdale Unit 11. The Board notes the position of EPGI and its witness that assigning costs to the PPA period would reduce the attractiveness of the units at auction. The Board considers it appropriate to first determine the equitable assignment of costs and if that determination results in some costs being assigned to the PPA period, such assignment is appropriate regardless of any perceived effect on the auction.

If, as the Applicants have noted and in accordance with section 44(2) of the GUR, the Board must assume for rate making purposes that the Rossdale plant will be decommissioned in total as of 31 December 2000, it would be clearly inconsistent to then allow for the recovery of costs that would be used to keep the plant in continued, regulated operation. Similarly, costs incurred for the benefit of Rossdale 11 should be paid for by the non-regulated entity and not by customers. The Board finds that there are some costs of this nature included in the Application by EPGI and will specify the amount of those costs in the following section of the Decision.

With regards to the 5% total threshold used as a benchmark before requiring a change in depreciation parameters, the Board notes that this threshold was established to avoid too much unnecessary "tinkering" with depreciation rates. This threshold was not established with the expectation that it would prohibit "truing up" capital cost recovery at the end of the capital's regulated life.

(D) Rossdale Decommissioning Allowed for 1999 and 2000

Concerns were raised as to whether or not certain costs included for future decommissioning at the Rossdale plant are properly part of a life extension of existing generation or are for the benefit of a non-regulated affiliate.

Position of ENMAX

ENMAX argued that it was apparent during cross-examination that the base lives for Rossdale Units 8, 9, and 10 have been lengthened. Subsequently, ENMAX confirmed that the IAT has lengthened the base lives for the Rossdale Units by letter dated 28 April 1999. The life extensions from the IAT go to the year 2003.

ENMAX argued that if these generating plants are scheduled to operate beyond 31 December 2000, the collection of decommissioning costs should be made on a fair basis from both the regulated and future PPA customers. Dr. White accepted that equal amounts of an asset's service value should be allocated to each year of the useful service life of that asset.[218] In the context of determining the service value of the Rossdale high-pressure plant, the net salvage value would be included in the calculation of service value. ENMAX requested that the Board

[218] Tr. p.1301

establish a mechanism to ensure that equal amounts of service value are allocated to each year of the remaining service life of these assets. ENMAX emphasized that the service life of the asset is not restricted to only regulated service. In providing such a mechanism, the Board could be assured that customers are only charged with their fair portion of the decommissioning costs.

ENMAX suggested a mechanism, in Exhibit 173, by which decommissioning costs could be collected in a deferral account. At the end of 2000, the Board could conduct a review of the life expectancy and decommissioning costs of these units. If the evidence suggested that the units will be in service through PPAs, a percentage of the collected decommissioning costs would then be refunded to the customers. If at the end of the year 2000, it became apparent that these units would be removed from service and decommissioned, EPGI would retain the funds that were collected in the deferral account.

ENMAX noted that, contrary to the argument of EPGI, sections 44(1) and 44(2), do not provide, either explicitly or implicitly, for the complete recovery of decommissioning costs. Sections 41 and 42 deal with the issue of decommissioning costs. The deferral account proposed by ENMAX would ensure that the power purchasers are committed to bearing only a fair share of decommissioning costs. It would also ensure that the parties to the PPA process would have the assurance that the decommissioning costs have been provided for in respect of the consumed service value of the generating unit. ENMAX argued it was clearly in the public interest, and consistent with all of the sections of the GUR, for the Board to implement the proposed deferral account mechanism.

Position of IPPSA/SPPA

The many issues relating to Rossdale form a clear example of the problems that arise when non-arms-length transactions occur between regulated and non-regulated affiliates. EPGI sought to "cash out" Rossdale units 8 - 10 by requiring consumers to bear the full depreciation and decommissioning cost for those units by the end of 2000—in spite of the fact they expected Rossdale 9 and 10 to run for five more years and intend to re-power Rossdale 8 (extending the life for 25 years). The Board is apparently constrained to make sure full recovery of Rossdale 8 - 10 is completed by 31 December 2000. Given the potential for life extensions, IPPSA/SPPA agreed with a deferral mechanism proposed by ENMAX.

IPPSA/SPPA noted that EPGI has incentives to minimize costs associated with the construction of their non-regulated Rossdale 11 unit by moving costs to the decommissioning of their regulated units.

Position of EPGI

EPGI proposed to recover the costs associated with decommissioning Rossdale such that the differences between the Monenco estimated costs and actual expenditures during 1996, 1997 and 1998 would be recovered in 1999 and 2000, and differences relating to actual expenditures during 1999 would be recovered in 2000. The total estimated and realized Rossdale decommissioning costs would be recovered by the end of 2000 consistent with sections 44(1)

and (2) of the GUR, which require that the Board assume that Rossdale Units 8, 9 and 10 will be decommissioned on 31 December 2000.

EPGI noted that Messrs. Stout and Kennedy suggested that the Board create a depreciation expense deferral account for Rossdale to reflect the fact that the lives of Rossdale Units 8, 9 and 10 may extend beyond 31 December 2000. During cross examination, Mr. Stout made it clear that ENMAX's recommendation is that the Board determine the appropriate decommissioning cost for Rossdale, allow that to be collected in 1999 and 2000, and then record the amount collected in 1999 and 2000 in a deferral account.[219] The balance in the deferral account would then be dealt with under the PPA regime if, in fact, the lives of the Rossdale units were extended. Mr. Stout agreed that if ENMAX's suggestion that the Board limit the total amount of decommissioning expense to be collected for Rossdale at $17.2 million were adopted and the decommissioning costs were in fact $30.9 million as set out in ENMAX-EPGI-57, then ENMAX's deferral account proposal would deny EPGI full capital recovery by the end of 2000 assuming that the units were decommissioned on that date.[220]

EPGI argued that the ENMAX deferral account proposal was precluded by sections 44(1) and (2) of the GUR. Those sections require the Board to assume for the purposes of the 1999/2000 GTA that the Rossdale Units will be decommissioned on 31 December 2000. Mr. Kennedy agreed that if the Rossdale Units were decommissioned on 31 December 2000, the units would not continue to operate beyond 2000, there would be no life extensions of the units and no PPAs would be sold with respect to the units.[221] Sections 44(1) and (2) make it clear that the Board must assume that this will be the case.

The ENMAX deferral account proposal, which is premised on Rossdale Units #8, #9 and #10 continuing operation past 31 December 2000, was an attempt to circumvent the clear requirements of sections 44(1) and (2) of the GUR. It was an attempt to draw the Board into doing indirectly what the Board is clearly precluded from doing directly. The GUR was explicitly enacted to relieve the Board of the need to look past specific decommissioning dates into the time period that would be dealt with by the IAT. It would be wholly inconsistent with the legislative intent behind sections 44(1) and (2) for the Board to approve depreciation rates for EPGI's Rossdale Units which are premised on the Units operating beyond 31 December 2000. Similarly, it would be wholly inconsistent with sections 44(1) and (2) for the Board to adopt a deferral account proposal which is clearly premised on the Units operating beyond 31 December 2000.

EPGI noted that the FIRM Customers recommended that the Board should maintain the 9.98% depreciation rate and $896,000 annual amortization for Rossdale approved in the 1996 GTA.[222]

---

[219] Tr. p.5380-5381
[220] Tr. p.5370-5371
[221] Tr. p.5363-5365
[222] Exhibit 42, p.14, l.12-15

The practical effect of the FIRM Customers' suggestion is that EPGI would not recover by the end of 2000 the expenses actually incurred with respect to Rossdale decommissioning from 1996 to the end of 1999, or some $13.7 million ($30.9 million – $17.2 million). Nor would the Rossdale Units be fully depreciated. The FIRM Customers' suggestion was premised on the Rossdale Units continuing operation beyond 2000 and, as such, was clearly precluded by the requirements of sections 44(1) and (2) of the GUR which, again, provide that the Board must assume that Rossdale Units 8, 9 and 10 are decommissioned on 31 December 2000.

The FIRM Customers further argued that there was no risk of under-recovery due to the presence of sections 42 and 43 of the GUR, which essentially provide an owner with a true-up opportunity in certain limited circumstances. EPGI submitted that it is not in the public interest for the Board to abdicate its responsibility to determine fair and reasonable depreciation expense for EPGI on the basis that there may be a "true-up" opportunity provided for in the future. EPGI argued that it had demonstrated the reasonableness of its depreciation expense and the Board should approve EPGI's request as applied for.

During cross examination, Mr. Stout raised the issue of the timing of recovery of cost variances for work to be completed in 1999 over the Monenco forecast, suggesting that if the Board were to approve the applied-for decommissioning cost, the Board should require EPGI to treat the cost variance as an adjustment to future net salvage for the purposes of calculating EPGI's depreciation expense for 1999 and 2000.[223] The result of this suggestion would be to shift the recovery of a portion of the decommissioning cost variance incurred in 1999 from the year 2000 back into 1999, somewhat "levelizing" EPGI's depreciation expense in 1999 and 2000 from the applied-for amounts.

In reply argument, EPGI argued that the GUR was explicitly enacted to relieve the Board of having to look past specific decommissioning dates into the time period that would be dealt with by the IAT. The deferral account proposal by ENMAX would be wholly inconsistent with that legislation. EPGI noted that ENMAX incorrectly asserted that the base lives of the Rossdale units had been "lengthened." EPGI was required, pursuant to the provisions of the EU Act, to file life extensions PPAs for the Rossdale units. There was no extension of the "base lives" of these units resulting from these PPAs.

EPGI countered the FIRM Customers assertion that the decommissioning costs associated with Rossdale "may relate to costs associated with the planning and construction of Rossdale Unit 11, a non-regulated portion of EPGI's business." EPGI argued that it had described the reasons for the increase in Rossdale decommissioning costs from the amount forecast and that the costs all related to the decommissioning of the site in a manner that was in the public interest of Albertans and will prevent the sterilization of the Rossdale site. Dr. Bridgeman had provided clear evidence that the Corporation had been mindful of the need to allocate cost appropriately.

[223] Tr. p.5359

Board Findings

Section 44(1) of the GUR instructs the Board to assume a decommissioning date of 31 December 2000 for the Rossdale generating units. As described in the previous section, the Board finds that this precludes any amortization of fair forecast decommissioning costs for the Rossdale high pressure plant beyond that date, regardless of whether or not the units are to continue in regulated service by way of a life extension through the PPA process.

In this instance, this would clearly create an undue burden on current customers if costs related to the operation of the plant into the future were forced to be collected from customers in 1999 and 2000. The Board is of the view that this is not the intention, nor the proper interpretation of the GUR.

The Board considers that a deferral account mechanism, as proposed by ENMAX and supported by IPCAA, is not consistent with the legislation.

However, the Board finds that the fair depreciation expense for Rossdale, that is consistent with the legislation, would see customers in 1999/2000 paying only those decommissioning costs that would be reasonably incurred if all the units were forecast to actually retire on 31 December 2000. In response to an undertaking from Mr. Berg,[224] EPGI provided such an estimate (the "notional plan"), resulting in an estimated cost reduction of $4.3 million to overall forecast decommissioning costs. The Board notes that the $4.3 million relates to decommissioning costs incurred after 1 January 1999 for the low pressure plant. With respect to the decommissioning costs incurred prior to 1 January 1999, the Board considers that EPGI has not provided an adequate explanation of the $3.7 million of costs that are in addition to the amount forecast by Monenco for the low-pressure plant equipment removal. In the absence of a satisfactory explanation, the Board concludes that these were costs incurred for new, non-regulated units or for the life extension of existing regulated units. Therefore, the Board directs EPGI, in its refiling, to reduce the 1999 and 2000 Rossdale depreciation expense to reflect a reduction of $8.0 million in forecast decommissioning costs.

The Board notes that EPGI made the following comment in Exhibit 57:

> The costs reflected in the "Actual Plan" are prudent and are properly included in EPGI's 1999/2000 GTA. If, however, the Board concludes that the difference in costs between the "Actual Plan" and the "Notional Plan" should not be included in the 1999/2000 GTA, EPGI respectfully submits that the Board must take steps to ensure that they are included in the PPAs determined for Rossdale units 8, 9 and 10.

[224] Exhibit 57

2. EPGI
(d) Depreciation

Following is the table extracted from Exhibit 57:

Line #		Actual Plan ($ million)	Notional Plan ($ million)	Difference ($.million)
1	Cost incurred prior to 1999	7.5	7.5	
2	Asbestos removal - Feb 1999	0.8	0.8	
	LP Plant			
3	• Building demolition – Monenco	1.6	1.6	
4	• Building demolition – additional	4.9	1.7	(3.2)
5	• Building maintenance	0.0	1.8	1.8
6	• Shops and stores relocation	1.5		(1.5)
7	• Services removal/relocation	3.2	1.6	(1.6)
8	Subtotal lines 2 to 7	12.0	7.3	(4.3)
9	HP Plant and Common	11.4	11.4	
10	Total	30.9	26.6	(4.3)

Source: Exhibit 57 undertaking page 1486 - 1489

The Board notes that section 42 of the GUR contemplates the decommissioning of a generating unit following a PPA life extension to its regulated service. The section clearly states that the owner of such a unit leaving regulated service is entitled to apply to the Board for recovery of any decommissioning costs not already paid by customers. The interpretation that the Board makes of this section is that the legislative framers had clearly contemplated the possibility that some decommissioning cost may be left to be collected, or refunded in the case of an over-collection, at the end of regulated life for Alberta generating units. Accordingly, the Board considers it unnecessary to take steps to ensure that the additional forecast decommissioning costs of $8.0 million are included in the PPAs determined for Rossdale Units 8, 9 and 10.

The Board does not accept EPGI's views that proper care has been taken to ensure that fair cost allocations have been made amongst regulated and non-regulated businesses. The Board's expectations in this regard have not been met.

The Board considers that any additional Rossdale decommissioning costs incurred as a result of the construction of Rossdale 11 should not be borne by the regulated business. The Board notes that this principle is consistent with the provision of section 45.5(2)(d) of the EU Act that requires the IAT to determine a method of allocating common costs of existing regulated units to new unregulated unit(s) that use the common facilities. Accordingly, the Board directs EPGI to identify any additional Rossdale decommissioning costs incurred as a result of the construction of any non-regulated unit(s) and subtract such costs from the actual decommissioning costs when

making an application under section 42 of the GUR to collect or refund any differences between actual and collected decommissioning costs.

(2) Technical Update

For 1999 and 2000, EPGI carried out a "Technical Update" of the depreciation rates currently in effect and proposed an improved method of tracking depreciation reserves. Depreciation and decommissioning expense for EPGI was forecast to be $64.7 million in 1999 and $73.8 million in 2000. The following table provides a comparison of EPGI's depreciation and decommissioning expense from 1996 to 2000.

Depreciation and Decommissioning Expense
($ million)

	1996 Reforecast	1996 Actual	1997 Actual	1998 Reforecast	1999 Forecast	2000 Forecast
Depreciation	51.0	51.0	52.2	53.4	57.2	63.6
Decommissioning	0.0	0.0	0.0	0.0	7.5	10.2
Total	51.0	51.0	52.2	53.4	64.7	73.8

Source: Application Section 3.6.1.2.

EPGI stated the increase in depreciation and decommissioning expense for 1999 and 2000 was primarily driven by the year of retirement for Rossdale in 2000. This retirement made adjustments necessary to reduce Rossdale's net book value to zero and to establish the approved balance of the decommissioning reserve by the end of 2000.

EPGI indicated the depreciation and decommissioning expense was derived through a Technical Update of EPGI's depreciation rates carried out by Dr. Ron White of Foster Associates, Inc. A copy of Dr. White's Technical Update was attached as Appendix "B" to the Application and the following is a summary of the key elements:

- The depreciation parameters (projection curves, projection lives and future net salvage rates) used in the 1996 Tariff Refiling were used in the Technical Update.
- Depreciation rates were updated to reflect updated composite service life statistics derived from the age distribution of surviving plants using forecast plant closing balances as of 31 December 1998.
- The average net salvage rates were updated to reflect a new weighting from actual and future retirement activity.
- The depreciation reserve for net salvage was split out from the depreciation reserve for the investment portion of all rate categories. This allowed EPGI to more accurately track

and adjusts rates to correct for potential imbalances between the theoretical and recorded reserves relating to the original investment versus the net salvage.

- Reserve imbalances between the theoretical and recorded reserves for each original investment account and each net salvage group were calculated.
- The recorded reserve was redistributed across all primary accounts by setting the primary account balance equal to the theoretical reserve balance and then scaling this balance up or down by the ratio of the total recorded reserve to the total theoretical reserve for each account grouping.
- Rates for amortizing the remaining imbalances over the remaining life of the assets were calculated.
- The depreciation expense for 1999 and 2000 was calculated as the sum of the 1999 and 2000 whole life depreciation accrual for the original investment plus the whole life accrual for net salvage plus the 1999 and 2000 portion of any amortized reserve imbalances stemming from the depreciation reserves for the original investments and net salvage.

EPGI noted that using the updated depreciation rates for the investment portion of each account and the updated net salvage rate for each grouping of plant accounts resulted in theoretical reserves that were approximately 15% greater in 1999 and 15% greater in 2000 than the recorded reserves.

The following tables provide a summary of the impact of the Technical Update on EPGI's forecast depreciation expense for 1999 and 2000.

2. EPGI
(d) Depreciation

Comparison of EPGI's Forecast Depreciation Expense in the 1996 Tariff Refiling and the 1999 Forecast ($ million)								
	1996 Refiling	1999 Before Technical Update			1999 After Technical Update			Difference resulting from Technical Update
	Total	Accrual	Amort	Total	Accrual	Amort	Total	Change
Rossdale								
Investment	1.7	1.8	0.0	1.8	1.3	4.9	6.2	4.4
Salvage	0.9	1.0	0.0	1.0	0.7	4.4	5.1	4.1
Total	2.6	2.8	0.0	2.8	2.0	9.3	11.3	8.5
Clover Bar								
Investment	3.8	4.4	(0.3)	4.1	5.2	0.3	5.5	1.4
Salvage	0.4	0.7	0.0	0.7	0.6	0.0	0.6	(0.1)
Total	4.2	5.1	(0.3)	4.8	5.8	0.3	6.1	1.3
Genesee								
Investment	41.1	40.5	0.4	40.9	40.0	1.2	41.2	0.3
Salvage	0.5	2.6	0.0	2.6	2.4	(0.6)	1.8	(0.8)
Total	41.6	43.1	0.4	43.5	42.4	0.6	43.0	(0.5)
General Plant	2.6			4.4			4.3	(0.1)
Total GENCO	51.0			55.5			64.7	9.2

Source: Application Table 9

EPGI noted the above table indicated that approximately $9.2 million of the forecast $11.3 increase ($64.7 million - $53.4 million) in depreciation expense for EPGI from 1998 to 1999 was a result of changes arising from the Technical Update. EPGI noted the majority of the increase stemmed from the amortization of reserve imbalances attributable to Rossdale scheduled to retire in 2000. EPGI stated that, prior to the Technical Update, the majority of the $2.1 million ($55.5 million - $53.4 million) increase in depreciation expense between 1998 and 1999 forecast arose from additions to the generation plant and generation net salvage.

2. EPGI
(d) Depreciation

Comparison of EPGI's Forecast Depreciation Expense in the 1996 Tariff Refiling and the 2000 Forecast ($ million)								
	1996 Refiling	2000 Before Technical Update			2000 After Technical Update			Difference resulting from Technical Update
	Total	Accrual	Amort	Total	Accrual	Amort	Total	Change
Rossdale								
Investment	1.7	1.8	0.0	1.8	0.7	8.9	9.6	7.8
Salvage	0.9	1.0	0.0	1.0	0.1	8.0	8.1	7.1
Total	2.6	2.8	0.0	2.8	0.8	9.3	17.7	14.9
Clover Bar								
Investment	3.8	4.8	(0.3)	4.5	6.5	0.2	6.7	2.2
Salvage	0.4	0.8	0.0	0.8	0.7	0.0	0.7	(0.1)
Total	4.2	5.6	(0.3)	5.3	7.2	0.2	7.4	2.1
Genesee								
Investment	41.1	40.8	0.3	41.1	40.6	1.2	41.8	0.7
Salvage	0.5	2.6	0.0	2.6	2.4	(1.0)	1.4	(1.2)
Total	41.6	43.4	0.3	43.7	43.0	0.2	43.2	(0.5)
General Plant	2.6			5.4			5.4	(0.0)
Total GENCO	51.0			57.2			73.7	16.5

Source: Application Table 10

The table above indicated, for 2000, that $14.9 million of the total increase in depreciation expense of $16.5 million was directly attributable to Rossdale.

The Board notes that, in addition to the Rossdale depreciation and decommissioning costs, there were four topics of concern to the Intervenors:

- the redistribution of depreciation reserves,
- the 5% "threshold" for amortizing reserve imbalances,
- the segregation of the decommissioning reserve from the investment portion of the depreciation reserve, and
- the use of the Technical Update for depreciation rates.

At the end of subsection (4), the Board will provide its directions to EPGI respecting the calculation of the allowed depreciation expense for EPGI for 1999 and 2000.

(A) The Redistribution of Depreciation Reserves

EPGI stated that, although reserve records were typically maintained by various account classifications, the total reserve for a company was the most important measure of the status of the company's depreciation practices and procedures. If a company had not previously conducted statistical life studies or considered retirement dispersion in setting depreciation rates, it was likely that some accounts would be over depreciated and other accounts would be under depreciated relative to a calculated theoretical reserve.

EPGI stated further that differences between the theoretical reserve and the recorded reserve would arise as a normal occurrence when service lives, dispersion patterns, and net salvage estimates were changed in the course of depreciation reviews. It was appropriate, therefore, and consistent with group depreciation theory, to periodically redistribute the total recorded reserve among the various account classifications based upon the most recent estimates of retirement dispersion and net salvage rates.

Position of the FIRM Customers

The FIRM Customers submitted the most significant matter before the Board was EPGI's proposed recovery of the reserve imbalance in the absence of adequate evidence demonstrating its appropriateness. The FIRM Customers suggested EPGI wore two hats, one as a regulated utility and the other as an unregulated power generator. The FIRM Customers noted the costs reflected in the amortization of the estimated reserve imbalance contained costs that, by EPGI's own admission, "may benefit the new addition", referring to Rossdale Unit 11, a proposed unregulated generating unit.[225]

The FIRM Customers stated EPGI was proposing to reallocate the reserve indicated in the Technical Update. In spite of Dr. White's suggestion this reallocation was common practice, the FIRM Customers suggested there was evidence to the contrary. The FIRM Customers noted there was no evidence to indicate this practice was used by either AE or TransAlta and suggested this was the first time such a method was proposed for EPGI.[226]

The FIRM Customers cited another inconsistency in Dr. White's approach was his claim that redistribution was necessary.[227] The FIRM Customers noted that EPGI admitted such redistribution might not be appropriate in every case.[228] The FIRM Customers concluded that, if redistribution was necessary, it should be necessary in all such instances not just those Dr. White deemed appropriate. The FIRM Customers submitted the lack of necessity was also evidenced by the Company's inability to identify any authoritative third party source in support of its position.[229]

---

[225] Tr. p.5525
[226] Tr. p. 5448
[227] Exhibit 175; p.17
[228] Tr. p.5445
[229] Exhibit 42; p.11

Finally, the FIRM Customers submitted the need for any redistribution was doubtful given the minimal impact.[230] The FIRM Customers suggested that if the proposed approach was not necessary and had only a minimal impact, its adoption would only add confusion. Therefore, the FIRM Customers recommended the Board not approve EPGI's request to redistribute its reserve.

Position of EPGI

EPGI noted the FIRM Customers' comment that EPGI now wears two hats, one as a regulated Utility and the other as an unregulated power generator. EPGI indicated the FIRM Customers further asserted that Mr. Pous' vague recitation of his experience with a certain U.S. utility somehow illustrated that "when a Utility wears two hats, as EPGI does in this instance, additional checks and balances must be established to protect the rights of ratepayers."[231]

EPGI submitted that it did not wear "two hats." EPGI owned and operated only regulated generating units. EPGI explained a separate company, EPCOR Power Development Corporation had interests in non-regulated generation.[232] Secondly, EPGI provided testimony that it had taken care to ensure proper cost allocations among regulated and non-regulated businesses, and this evidence was uncontroverted.[233] EPGI noted that the FIRM Customers pointed to Mr. Pous' vague discussion of an experience he apparently had with one utility in a different jurisdiction as support for his position that something more was required to ensure that customer's interests were fully protected. EPGI submitted that the only reliable testimony on this issue was that of Dr. Bridgeman.

EPGI stated that the redistribution of reserves was straight-forward and well founded in group depreciation theory. EPGI noted the sound rationales for redistributing reserves were explained on page 7 of the 1999 and 2000 Technical Updates and cited in Dr. White's rebuttal evidence as follows:

> A redistribution of the recorded reserve is particularly appropriate for Edmonton Power Generation Inc. and Edmonton Power Transmission Inc. at this time. In the past, a net salvage component was included in the Companies' depreciation rate and accrued into reserves that were maintained by primary account. It is proposed in this update to segregate the recorded reserve into an investment portion and a net salvage portion, such that net salvage can be accrued and recorded at the function or major plant location level and depreciation expense (exclusive of net salvage) can be accrued by primary account. A redistribution of the recorded reserve is necessary, therefore, to develop an initial investment reserve balance for each primary account and a net salvage reserve balance for

[230] Tr. p. 5539
[231] FIRM Argument, p.96
[232] Tr. p.1236
[233] Tr. p.1353-1355

each rate category consistent with the estimates of retirement dispersion, service life statistics and net salvage rates developed in the update.

Also, in the past, common plant reserve balances for Genesee Units 1 and 2 and general plant reserve balances for the GENCO business unit were derived from allocations. The basis for the allocation did not provide for consistency in the amount of the accrued reserve from one year to the next. In the course of the technical update, a common function was created for Genesee which eliminated the need to allocate plant and reserves to the generating units. Similarly, a common function was created for general plant and reserves previously allocated among business units. A redistribution of the reserve is needed, therefore, to develop an initial reserve balance for each of these new account classifications.

A redistribution of the recorded reserve is also a sensible way to reduce accrual rate differences attributable to offsetting errors in parameter estimates. All other things being equal, transferring reserves from an account that is excessive to an account that is deficient will reduce the components in remaining-life accrual rates that are working against each other to amortize reserve imbalances. A periodic realignment of parameters and reserves will tend to eliminate large differences in the accrual rates to accounts having similar parameters and will provide a degree of uniformity in the accrual rates authorized by regulation for similar utilities.[234]

In response to FIRMD-EPGI-15, EPGI provided a list of some 26 utilities for which depreciation reserves had been redistributed by Dr. White, and the regulatory docket or case numbers where applicable. During examination by the Board, Dr. White testified that the redistribution of the depreciation reserve had no impact on Rossdale depreciation expense and only a minimal overall impact as the redistribution was done within plant locations and functions.[235]

EPGI noted the FIRM Customers referenced Dr. White's evidence that the redistribution of the recorded depreciation reserve might not be appropriate in every circumstance, and made the assertion that, "Arguably, if it is necessary, it should be necessary in all such instances not just those Dr. White deems appropriate." However, EPGI submitted circumstances of a particular utility at a given point in time might be such that a redistribution might not be appropriate. This situation was recognized by Messrs. Stout and Kennedy in their statement that the appropriateness of redistributions of the recorded reserve depended on many circumstances. EPGI submitted that, to argue if a redistribution was appropriate for one utility it must be appropriate for all, ignored the various reasons for performing a redistribution and was contrary to common sense.

[234] Exhibit 175, p.17
[235] Tr. p.5539

Messrs. Stout and Kennedy agreed that EPGI's redistribution of reserves was appropriate:

> The appropriateness of redistributions of the recorded reserve depends on many circumstances including the level at which the redistribution occurs, the concept of depreciation used and regulatory precedent. In general, redistributions within station or function such as those performed by EPGI are reasonable.[236]

EPGI could not determine where the source of any confusion on the part of the FIRM Customers might lie. EPGI submitted that Messrs. Stout and Kennedy expressed no "confusion" as to EPGI's overall approach, and the Board clearly indicated through its questions of all the various depreciation witnesses that the Board was not "confused" by anything EPGI had done. EPGI suggested that, if the FIRM Customers found anything EPGI had done as adding "confusion," then the FIRM Customers were the only party with this difficulty.

EPGI submitted the FIRM Customers provided no analysis or substantiation to assert that EPGI's approach added confusion or clouded anything. EPGI suggested that the FIRM Customers did not provide any analysis or identify any evidence demonstrating that EPGI's approach was based on anything other than sound rationales and accepted depreciation theory and practice.

EPGI asserted there was no basis for the FIRM Group's criticism of the redistribution of depreciation reserves as carried out by EPGI. EPGI stated the approach taken was clear, reasonable, and consistent with the principles of depreciation theory and should be approved.

Board Findings

The Board accepts that there are circumstances under which it is appropriate to redistribute the actual depreciation reserve. However, the Board considers it important to examine the account level at which the redistribution occurs. The Board notes the evidence of Dr. White that the redistribution had no impact on the Rossdale depreciation expense and only a minimal overall impact on other accounts as the redistribution was done within plant locations (i.e. within Rossdale, Clover Bar and Genesee) and functions. The Board considers such a redistribution within plants to be appropriate since it eliminates the possibility of inequities that could result if excesses or deficiencies from a longer life plant were, for example, loaded onto a shorter life plant. Further, the Board considers that the accuracy of current and future depreciation expense by primary account within the plant locations will be improved through redistribution. Accordingly, the Board approves EPGI's method of redistributing the depreciation reserve.

(B) The 5% Threshold for Amortizing Reserve Imbalances

A reserve imbalance is the difference between the relative positions of the booked reserve (Booked Depreciation Reserve) and the reserve which would exist had today's best estimates of

[236] EPGI/EPTI-ENMAXD-7

depreciation parameters been used from the time the plant had been placed in service (Theoretical Depreciation Reserve). Tolerance limits of ± 5% are placed around the level of the Theoretical Depreciation Reserve whereby correction procedures are invoked only if the Booked Depreciation Reserve is outside these limits.

Position of the FIRM Customers

The FIRM Customers suggested EPGI ignored the Board's long and consistent practice of limiting the amortization of reserve imbalances to situations where the imbalance exceeded a 5% threshold. The FIRM Customers stated that EPGI chose to ignore this practice resulting in an increase in depreciation expense of approximately $250,000 annually for 1999 and 2000. The FIRM Customers submitted there was no evidence to support a change in the Board's practice. Therefore, the FIRM Customers recommended EPGI's proposed increase due to the change in amortization should not be allowed.

Position of EPGI

EPGI countered the FIRM Customers argument that EPGI ignored the "5% reserve amortization threshold" in developing the depreciation proposal. EPGI stated there was no legal or regulatory requirement to mandate such a threshold. EPGI submitted that, at most, the threshold was a practice that had arisen in this jurisdiction and, as such, must be examined by the Board based on the particular facts of each case. EPGI noted the FIRM Customers provided no substantive basis for imposing the 5% threshold in respect of EPGI in this case.

Dr. White testified that there was no basis for the assertion by the FIRM Customers that EPGI had "ignored" the 5% threshold:

> It was clearly stated in the Technical Updates that remaining-life rates were proposed for all depreciable plant categories. While I am aware that prior Board practices have restricted the amortization of reserve imbalances to those categories in which the imbalance exceeded five percent of the theoretical reserve, I am unaware of any rule or regulation that would prohibit EPGI from requesting remaining-life rates for all non-amortized accounts. The Company did not "ignore" the so-called "5% reserve amortization threshold". The motivation for requesting remaining-life rates was to initiate corrective action when imbalances are detected. This, in my opinion, is a commendable step toward more nearly achieving the goals and objectives of depreciation accounting.

During cross-examination, Dr. White testified as follows:[237]

> Q I'm just wondering, why did EPGI deviate from that normal 5 per cent reserve amortization threshold?

[237] Tr. p. 5537-5538

A DR. WHITE: Actually, the technical update and the assumption of a remaining life rate on all of the plant categories was my treatment. I was aware that the Board in the past has placed some kind of threshold in the 5 percent, in particular, on the amortization of the reserve imbalance.

My sense was that particularly moving into the environment that we are moving into now, there is no compelling reason to postpone addressing any reserve imbalance, whether it be positive or negative.

Remaining life rate in my view is totally appropriate, and so I simply adopted a remaining life rate to address those balances -- imbalances, both positive and negative at this point in time.

EPGI stated there was no reasonable basis for imposing a threshold on the amortization of reserves in respect of EPGI's 1999 and 2000 Application. EPGI noted that the only reason the FIRM Customers raised the issue was that imposition of the threshold would result in a minor reduction to EPGI's depreciation expense in 1999 and 2000. EPGI asserted that, contrary to the FIRM Customers' position, there were compelling reasons to adopt Dr. White's approach of resolving all reserve imbalances, both positive and negative, in 1999 and 2000. EPGI noted 1999 and 2000 were the last two years of regulated service for the generating units in question prior to the PPA regime coming into place.

EPGI countered the FIRM Customers' claim that no evidence was presented to support a change in the Board's practice of limiting the amortization of reserve imbalances to situations where the reserve imbalance exceeded a 5% threshold. EPGI stated uncertainty as to whose position the FIRM Customers were addressing. EPGI did not suggest that the Board had changed the practice of limiting the amortization of reserve imbalances. EPGI submitted that this practice was not appropriate in these circumstances for the reasons noted.

EPGI submitted the FIRM Customers provided no evidence or argument of any substance suggesting that the Board's prior practice should be applied in this case. EPGI submitted that the FIRM Customers' statement that the practice should be applied to EPGI was not sufficient grounds for the Board to take such action, particularly in light of the sound rationales that had been provided supporting EPGI's proposal.

Board Findings

The Board notes that the 5% total threshold is used as a benchmark before requiring a change in depreciation parameters. The Board notes that this threshold was established recognizing the uncertainty of future estimates and to avoid unnecessary adjustments to depreciation rates. The Board considers this threshold was not established with the expectation that it would prohibit "truing up" capital cost recovery when the estimate of parameters become more certain towards the end of the asset's regulated life. Accordingly, the Board agrees with EPGI that it would not

be appropriate to invoke the 5% threshold for Rossdale which is a plant that is at the end of its regulated life. However, the Board is not persuaded that its normal practice of a 5% threshold should be abandoned for longer lived plants such as Clover Bar and Genesee. Accordingly, the Board directs EPGI, in its refiling, to recalculate its depreciation expense using the 5% threshold for amortization of depreciation reserve imbalances for all accounts except the Rossdale plant accounts.

(C) The Segregation of the Decommissioning Reserve

Position of the FIRM Customers

The FIRM Customers noted that EPGI was proposing to segregate the accumulated provision for depreciation into an investment component and a net salvage component. To the FIRM Customers' knowledge, this practice was never employed before in Alberta. The FIRM Customers indicated that, given this Application was the last rate proceeding pertaining to generation investment, the FIRM Customers suggested it seemed odd to request a new and questionable process or procedure be implemented for the two year period immediately preceding the introduction of a PPA regime. The FIRM Customers submitted the approach taken by EPGI in the last case provided a better presentation and a more forthright approach. The FIRM Customers suggested the inclusion of another new wrinkle in the depreciation process continued EPGI's persistent efforts to cloud other, more significant issues such as the significant and unsupported increase in decommissioning costs for the Rossdale plant.

The FIRM Customers noted Dr. White claimed the proposed segregation of the reserve was not an uncommon practice.[238] However, the FIRM Customers stated that, when EPGI was requested to identify companies following such a practice (and approved by the governing regulatory bodies), the facts contradicted Dr. White.. The FIRM Customers submitted that while Dr. White identified seven utilities carrying out such segregation of their reserve, three were electric co-operatives rather than investor owned utilities and the other four were investor-owned utilities affiliated through a single holding company. The FIRM Customers noted Dr. White admitted all of the cases identified resulted in settlements and he was unaware if the settlement language contained prohibitions against assigning any value to such practice as a precedent.[239] The FIRM Customers noted that Dr. White did not perform such segregation of the reserve for other utilities where he performed depreciation analyses.[240]

In summary, the FIRM Customers believed where the regulation of particular assets was being phased out, it was inappropriate to add further processes and confusion providing little, if any, benefit when compared to existing methods. Consequently, the FIRM Customers recommended the Board not approve the segregation of the reserve in this proceeding.

---

[238] Tr. p.1326
[239] Tr. p.5449
[240] Tr. p.5455

Position of EPGI

EPGI noted the FIRM Customers' assertion that EPGI's segregation added confusion and provided no useful benefits. Dr. White testified as to the rationale for segregating the reserve as follows:

> Foster Associates, however, is recommending a change in the recording of interim net salvage and future dismantlement costs that represents a departure from the current practice of Edmonton Power Generation Inc. and Edmonton Power Transmission Inc. The Companies are currently accruing for interim net salvage and future dismantlement costs as a component of the primary account depreciation rate. This treatment produces a commingled depreciation reserve in which reserve imbalances created by net salvage parameters cannot be separated from imbalances created by service life statistics. Stated differently, the portion of the depreciation reserve attributable to net salvage cannot be isolated from the portion attributable to the allocation of the original cost of plant and equipment to operations.
>
> It is opinion of Foster Associates that accounting for salvage and removal expense can be improved and simplified by establishing a separate accrual rate for net salvage at the function level (or by major plant locations) and maintaining an associated net salvage reserve. The benefits of this treatment include improved monitoring of the adequacy of the estimated net salvage rates and elimination of the need to identify net salvage proceeds by primary plant account. [241]

EPGI noted benefits were derived from segregating the reserves and suggested a consistency with the requirement of establishing a PPA for each regulated generating unit. EPGI submitted the FIRM Customers provided no substantive evidence to demonstrate otherwise. Accordingly, EPGI recommended the Board approve the proposed segregation of reserves.

Board Findings

The Board considers that the rationale for segregating the depreciation reserve into an investment reserve and a net salvage reserve is sound. The Board agrees with EPGI that the segregation of the depreciation into these two components is appropriate and improves the monitoring of the adequacy of the total depreciation reserve. Accordingly, the Board approves the segregation of the total depreciation reserve into an investment depreciation reserve and a net salvage depreciation reserve at the functional level (or by major plant locations).

[241] Exhibit 175, p.18, lines 12 to 29

(D) The Use of the Technical Update for Depreciation Rates

Position of the FIRM Customers

The FIRM Customers noted, from the last proceeding, that customers had been subjected to incorrect estimations regarding depreciation expense from EPGI since 1983. The FIRM Customers stated that the time had come for the Board to refuse EPGI's request to inflict another inaccurate estimate upon customers, particularly as this appeared to be the last rate proceeding for EPGI. The FIRM Customers asserted the Board must demand EPGI meet some minimum burden of proof. The FIRM Customers submitted EPGI had failed to meet any reasonable standard for supporting its position other than to make hollow statements and provide limited summary numbers. The FIRM Customers submitted EPGI's comments did not provide verifiable or supportable proof of its position.

The FIRM Customers noted EPGI proposed to establish a basis for recovery of depreciation expense through a Technical Update rather than a traditional depreciation study. The FIRM Customers suggested EPGI chose not to perform a detailed net salvage analysis. Instead, EPGI accepted a knowingly incorrect decommissioning value of $17.2 million with the intent of recovering all estimated and actual amounts through a reserve imbalance amortization.

The FIRM Customers indicated EPGI was aware this proceeding would be the last regulated rate case for electric generation investment. The FIRM Customers inferred that EPGI chose to adopt a totally inappropriate procedure (a Technical Update) as a means of justifying a request for a substantial increase. As the FIRM Customers had stated before, EPGI made no attempt to develop or present a more accurate and current net salvage study. The FIRM Customers submit that, as a result, the record was entirely devoid of any detailed information regarding specific reasons for each of the cost variances.

The FIRM Customers stated there was no evidence to demonstrate whether the allocation of such costs to regulated customers was appropriate. Rather, the FIRM Customers suggested the Technical Update served the best interests of EPGI and did not present the clearest and most forthright listing of the significant cost increases. The FIRM Customers noted this was evident in terms of parties' inability to reasonably compare the current information with evidence from prior proceedings. The FIRM Customers suggested that, if EPGI's approach were adopted, the Board and ratepayers would be denied the right of having a reasonable opportunity to test the accuracy of EPGI's presentation.

The FIRM Customers noted that, in addition to eliminating the opportunity for a proper review, using the Technical Update afforded EPGI additional, somewhat dubious benefits. The FIRM Customers stated that, since there was no set process associated with the preparation of a Technical Update, EPGI was free to allow Dr. White any modifications or inconsistent treatments he might deem appropriate for developing the depreciation request. The FIRM Customers suggested the example where Dr. White admitted he "generally" retained parameters

in a Technical Update.[242] The FIRM Customers submitted that, if a process was only "generally" followed, it also followed the author had some freedom to change or modify whatever data or analyses might be necessary to achieve a desired goal or outcome.

The FIRM Customers suggested this lack of established and recognized protocols was further illustrated by Dr. White's references to depreciation terminology as generally accepted by depreciation specialists but with the caveat "in the context of the technical update."[243] The FIRM Customers indicated this distinction was important since the same words apparently mean something different in the general context of depreciation.[244] Moreover, Dr. White admitted that, within the limits of a Technical Update, he could not change the future dismantling cost estimate from the level adopted by the Board in the 1996 GTA, even though he knew such an estimate was no longer valid.[245] Finally, the FIRM Customers submitted a lack of more formal processes in a Technical Update, permitted Dr. White to ignore the dissimilarity between the treatment he proposed in his Technical Update and the one AE performed in its depreciation study.[246]

Based on the foregoing, the FIRM Customers saw little, if any benefit in adopting EPGI's selection of a Technical Update for the calculation of depreciation expense in this proceeding. The FIRM Customers stated the Technical Update approach was a mechanism to present EPGI's request in other than a clear and forthright manner. The FIRM Customers submitted such an approach was unacceptable, particularly given the level of the increase requested. Accordingly, the FIRM Customers requested the Board to reject EPGI's request.

Position of EPGI

EPGI stated the FIRM Customers unfairly criticized both the Board and EPGI, by stating that customers have been subjected to incorrect estimations regarding depreciation expense from the Company since 1983. EPGI suggested the FIRM Customers provided no basis for such an unwarranted criticism. EPGI submitted it had consistently proposed fair and reasonable forecasts of its depreciation expense based on the best available information.

EPGI stated that the FIRM Customers made numerous irrational assertions that have no basis in fact. For example, EPGI indicated the FIRM Customers asserted that customers had not been given a fair opportunity to test the company's case, but were forced to accept whatever application may be proposed. EPGI noted the FIRM Customers' statement that, if EPGI's approach to determining its depreciation expense was accepted, the right to a reasonable opportunity to test the accuracy of EPGI's presentation will be denied.

---

[242] Tr. p.5422
[243] Tr. p.5429
[244] Tr. p.5429
[245] Tr. p.5521
[246] Exhibit 126, FIRMD.EPGI-44 (f)

EPGI summarized the substantial and detailed evidence in its argument that formed the basis for EPGI's applied-for depreciation expense. EPGI and Dr. White provided full responses to all information requests and the large number of questions asked during cross-examination relating to its depreciation evidence. EPGI indicated the FIRM Customers apparently saw no need to follow up further with EPGI for further details respecting EPGI's approach or applied-for depreciation costs either in responses to information requests or through cross examination. EPGI noted the FIRM group had no trouble contacting EPGI to obtain further information on responses to information requests, including those relating to depreciation, nor did the FIRM Customers hesitate to ask detailed "information request" type questions in cross-examination of EPGI's witnesses respecting other aspects of EPGI's Application.

In this regard, EPGI noted that in response to FIRMD-EPGI-19, the FIRM Customers were provided with a copy of EPGI's demolition contract with McColman & Sons respecting the LP plant equipment removal during the period 1996 to 1998. EPGI stated this contract related to work forecast by Monenco to cost $1.7 million but proved to actually cost $5.5 million as shown in ENMAX-EPGI-57. EPGI noted the FIRM Customers did not challenge EPGI's witnesses with respect to this contract or the amounts paid by EPGI under the contract, nor did the FIRM Customers proffer evidence challenging the reasonableness of those amounts. EPGI also noted that FIRMD-EPGI-19 confirmed the shortfall in the salvage value that was realized compared to the Monenco forecast.

EPGI submitted information was provided in support of its applied-for depreciation expense and, the opportunity was available to the Intervenors, on two occasions, to pose information requests, to follow up on EPGI's responses through further discussion, to cross examine and to submit final argument. EPGI submitted it was erroneous for the FIRM Customers to now assert that Intervenors had been provided with anything less than a fair opportunity to test EPGI's Application.

Board Findings

The Board accepts EPGI's evidence that the depreciation parameters (projection curves, projection lives and future net salvage rates) used in the 1996 GTA Refiling were used in the Technical Update. The Board considers this update to depreciation expense to be a normal practice and within the bounds of a "Technical Update." The Board notes the correction to the Rossdale and Clover Bar forecast decommissioning reserves identified by EPGI in Exhibit 8 to account for decommissioning work that will have been completed in advance of the year of final retirement. The Board has dealt with the forecast decommissioning costs for Rossdale in the Rossdale Decommissioning section of this Decision. Further, in the case of the Rossdale plant, the Board finds in this situation of a large final retirement, that rate stability would be assisted by allocating an equal amount of allowed remaining investment and allowed decommissioning costs to 1999 and 2000.

Accordingly, the Board approves EPGI's forecast depreciation expense arising from the Technical Update as corrected for Rossdale and Clover Bar decommissioning reserve errors, the

Board's findings respecting Rossdale decommissioning costs, the equalization of depreciation expense for Rossdale in 1999 and 2000 and the application of the 5% threshold.

(E) Summary of Board Findings

The Board directs EPGI, in its refiling, to:

- Reduce the forecast decommissioning expense for Rossdale by $5.823 million to reflect the error identified in Exhibit 8.
- Reduce the forecast decommissioning expense for Rossdale by a further $8.0 million to reflect the Board's findings in the Rossdale Decommissioning section of this Decision.
- Adjust the depreciation expense for Rossdale such that equal amounts of allowed investment accruals and equal amounts of allowed decommissioning costs are allocated to 1999 and 2000.
- Reduce the forecast decommissioning expense for Clover Bar by $2.333 million to reflect the error identified in Exhibit 8.
- Reduce the depreciation expense by $0.255 million (adjusted by the effect, if any, of Rossdale) in each of the years 1999 and 2000 to reflect the Board's findings that the 5% threshold for amortization of depreciation reserve imbalances applies for all accounts except the Rossdale plant accounts.

(e) Reservation Price–Normalization Costs

EPGI provided a summary of the Normalization of EPGI's Reservation Price in 1999 and 2000. EPGI provided a calculation after normalizing for ancillary service payments, restructuring costs under section 78, dragline operating benefits, decommissioning costs associated with the Rossdale LP plant, Y2K outage impacts and inflation.

The purpose of EPGI's calculation attempted to demonstrate that EPGI's normalized Reservation Prices in 1999 and 2000 were lower than the normalized Reservation Price in 1996 as shown in the following table:

	1996 Refiling	1999 Forecast	2000 Forecast
Prior to Normalization			
fixed costs	288.7	312.0	315.7
surplus/shortfall	3.9	3.0	(3.8)
fixed ancillary service revenue	(6.3)		
Reservation Price	286.3	315.0	311.9
Adjustments			

fixed ancillary service revenue		(6.3)	(6.3)
section 78 costs	(0.2)	(1.3)	(0.3)
dragline operating benefits		(2.8)	(2.8)
Rossdale LP decommissioning costs		(2.6)	(10.8)
Y2K outages		(10.9)	0.6
	286.1	291.1	292.3
Normalized Reservation Price			
normalized fixed costs	288.5	305.3	301.8
normalized surplus/shortfall	3.9	7.9	3.2
normalized fixed ancillary service revenue	(6.3)	6.3	6.3
normalized nominal reservation price	286.1	291.1	292.3
Inflation rate	100.0	104.5	106.2
Real Reservation Price in 1996 dollars	286.1	278.7	275.1

Source: Exhibit 23, Tr. p. 235

Position of ENMAX

ENMAX presented graphs, Exhibits 18 and 19, that showed, based on EPGI's historical filings, IR responses and the Application, the increases in Aggregate Reservation Price (ARP) and Genesee UOP. ENMAX indicated that, in Exhibits 8 and 23, EPGI attempted to explain that Exhibits 18 and 19 were incorrect. ENMAX noted that EPGI offered explanations indicating that Exhibits 18 and 19 did not reflect "normal" expenditures.

ENMAX stated that whether or not the graphs in Exhibits 18 and 19 reflected "normal" costs was irrelevant. ENMAX indicated these exhibits reflected the costs which EPGI had applied to collect in its 1999 and 2000 tariffs. ENMAX submitted if EPGI objected to the use of raw or unadjusted data and proposed that the "normalized" amounts were the appropriate ones, then EPGI should amend its application for tariffs based on such amounts. ENMAX also submitted if EPGI would like the Board and customers to rely on the "normalized" amounts, then its the normal amounts that should be used for the ARP and Genesee UOP.

ENMAX agreed that, in the past, the Board had adjusted applicants' requests to remove abnormalities or to spread large or unusual amounts over a longer period than the test period. However, ENMAX understood that EPGI was not proposing this treatment with respect to costs, abnormal or otherwise. ENMAX suggested if EPGI did not propose to use the "normalized" data for ARP and Genesee UOP purposes, then the normalization process was an interesting academic exercise that had no bearing in reality.

ENMAX suggested EPGI's effort in this regard only served to highlight the extreme nature and extent of the increases proposed for its 1999 and 2000 costs. ENMAX submitted that EPGI's efforts in massaging the data in an attempt to rationalize cost increases should be ignored.

Position of LE/RD

LE/RD noted that EPGI offered normalized calculations for the test years. LE/RD noted EPGI supported the proposition that there was no serious upward trend in its filing, but that such increases were caused by inflationary pressures or unusual one-time events that would have to be removed in order to have results compared on a consistent basis. LE/RD suggested the problem with normalizing was that, unless an equivalent examination of the years against which the test years were being compared was provided, the exercise was not necessarily useful as there might be similar one-time occurrences in prior years which should also be removed for comparative purposes. LE/RD submitted the only conclusion that could be reached with such analysis was that if the costs had not gone up, they would have gone down.

Position of EPGI

EPGI noted that certain parties asserted that because some of EPGI's costs were higher than in prior years, sufficient grounds were provided for the Board to either apply broad reductions to EPGI's 1999 and 2000 costs or limit those costs to prior years' levels. EPGI stated that, while arguments of this nature might be attractive to certain parties because these arguments were easy to make and did not require the party to provide argument on the evidence actually before the Board, such arguments did not assist the Board.

EPGI noted in its opening statement that EPGI had been careful to prudently control its costs for 1999 and 2000. EPGI noted Exhibit 23 where, on a comparative basis, EPGI's costs were lower for each of 1999 and 2000 than for 1996, the year in which the Board last undertook a detailed examination of EPGI's costs.

In making their assertions, EPGI suggested Intervenors ignored the detailed evidence and relied on superficial cost comparisons with prior years. EPGI, in reply argument, described the unreliability inherent in Intervenors' historical comparisons with respect to the Application. EPGI noted, for example, the "connected-the-dot" line graphs in Exhibit 18, proffered by ENMAX, failed to account for one-time or unusual items, such as those identified by EPGI in Exhibit 23. EPGI summarized that this exhibit demonstrated that if appropriate adjustments were made for costs that were unique to 1999 and 2000, EPGI's reservation prices for 1999 and 2000 were in fact lower than its 1996 reservation price. EPGI identified those items requiring adjustment as:

- fixed ancillary service payments
- section 78 costs
- dragline operating benefits
- decommissioning costs for the Rossdale LP plant
- surplus/shortfall impact of Y2K outages
- inflation

EPGI noted that none of the Intervenors cross-examined or took issue in final argument with the calculations and factors identified in Exhibit 23 and ENMAX-EPGI-28.

EPGI noted ENMAX's position that normalizing costs for unusual one-time items was not a valid exercise and that the normalization of EPGI's costs "only serves to highlight the extreme nature and extent of increases proposed for its 1999 and 2000 costs." EPGI stated these assertions ignored the fact that the normalization of EPGI's costs provided EPGI with a means of the main cost drivers that resulted in overall cost increases from prior years, as well as a means of assisting parties in determining that other costs have remained at reasonable levels. EPGI suggested normalizing its costs allowed EPGI to provide a clear and forthright explanation of cost variances from prior years and enabled the Board and Intervenors to gain a better understanding of the components of the costs which formed the basis for EPGI's reservation prices.

EPGI noted that, notwithstanding ENMAX's suggestion that EPGI's normalization of costs should be ignored, ENMAX acknowledged that forecast cost increases over historical actuals, which could be demonstrated to be necessary and reasonable, should be approved. EPGI stated the extensive evidence, provided by EPGI, explained and addressed the need for and reasonableness of the various components of EPGI's forecast O&M costs and capital additions, and was more cogent and reliable than the historical comparisons proffered by Intervenors.

EPGI noted LE/RD argued that normalizing costs was not valid unless there was an equivalent examination of the years against which the test years were being compared. EPGI noted that neither LE/RD nor any other Intervenor identified any specific costs in previous years that should be excluded from a normalized comparison. EPGI submitted that the analysis was reasonable and reliable.

EPGI also noted that the FIRM Customers acknowledged the concept behind normalizing costs for comparison purposes by acknowledging that the FIRM Customers recognized the need for Y2K capital additions as outside the normal scope of capital additions. EPGI concluded that the FIRM Customers would agree that Y2K O&M expenses should also be outside the normal scope of O&M expenses. EPGI submitted Exhibit 23 demonstrated that Y2K outages had a $10.9 million impact on EPGI's shortfall in 1999, a fact which the FIRM Customers appeared to ignore in arguing that increases in EPGI's 1999 and 2000 reservation prices were driven by industry restructuring and positioning for the PPA world.

Board Findings

The Board finds that the information presented is helpful to understand why the tariff is above or below what may be considered as "normal." The Board agrees with LE/RD that the concept that all "one-time" or "unusual" costs must be accounted for and removed from the data each year is necessary in order for the normalization to have any meaning. The Board also notes that the parties will not always agree on which costs can be considered as single event costs for normalization purposes. However, the Board considers a reconciliation, which continues from one year to the next, provides a useful base of information for future normalization presentations.

3. EPTI

(a) Necessary Working Capital

The inclusion of necessary working capital (NWC) in rate base recognizes the average investment required by a utility to bridge the lag between when the service was rendered and the related expenses were incurred and when the revenues were received to recover such expenses. NWC also includes amounts reflecting the investment in inventories of materials, supplies and other assets necessary to the operation and maintenance of the utility system.

EPTI filed working capital calculations by updating the various lead/lag schedules for current payment and receipt patterns. EPTI indicated that many of the changes were minor in nature but were accounted for in the lead/lag schedules. The following table summarizes EPTI's working capital requirements for 1999 and 2000.

	1999		2000	
Working Capital Requirements	Lead/ Lag Days	Working Capital ($million)	Lead/ Lag Days	Working Capital ($ million)
Operating expenses	27.2	0.9	28.0	0.9
Inventory		0.3		0.3
Mid-year Debt Interest	(81.7)	(2.2)	(75.9)	(2.0)
Mid-year Equity				
Common return	42.6	0.3	42.6	0.3
Dividend return	27.4	0.2	27.4	0.2
Mid-year Depreciation	42.6	0.4	42.6	0.5
Total Working Capital		(0.1)		0.2

Source: EPTI Application Schedules T-7-1999 and T-7-2000

Intervenors did not express any concerns directly with respect to EPTI's calculations of Necessary Working.

Board Findings

The Board notes that Intervenors did not provide argument and reply argument specific to EPTI. The Board considers that the EPGI decisions with respect to the necessary working capital will apply equally to EPTI. Therefore, the Board directs EPTI, in its refiling, to adjust the lag days

on operating expenses to reflect the time between rendering of service and the issue date of suppliers' invoice for 15 days.

Further, the Board directs EPTI, in its refiling, to deem a quarterly payment of dividends in the calculation of necessary working capital.

The Board has provided its findings on inventory valuation in Part 1 – General of this Decision. For purposes of this Decision, the Board accepts EPTI's mid year inventory valuation for working capital of $0.3 million each for 1999 and 2000.

The Board has reviewed and accepts the lead/lag calculations for all remaining items in the calculation of necessary working capital for 1999 and 2000. Therefore the Board directs EPTI, in its refiling, to use the lead/lag days as calculated for the remaining components of necessary working capital for 1999 and 2000.

The Board notes that EPTI has been directed to make changes to the costs in each expense category. The Board directs EPTI, in its refiling, to revise the 1999 and 2000 necessary working capital using the Board approved costs in each expense category.

(b) Cash Operating Expense

(1) Operating and Maintenance

EPTI forecast transmission operations and maintenance cost at $6.9 million for both 1999 and 2000. These amounts represented an increase of $1 million from EPTI's 1996 GTA Refiling. A breakdown of EPTI's operations and maintenance cost is shown on the following schedule:

	1996 Refiling	1996 Actual	1997 Actual	1998 Reforecast	1999 Forecast	2000 Forecast
					Adjusted for Exh 8	Adjusted for Exh 8
Maintenance						
System	0.3	0.3	0.2	0.2	0.2	0.2
Substation	1.8	1.5	1.4	1.8	1.6	1.5
Telecontrol	0.2	0.2	0.2	0.2	0.4	0.4
Total Maintenance	2.3	2.0	1.8	2.2	2.2	2.1
Operations						
System	1.6	1.4	1.3	1.3	1.7	1.6
Substation	0.1	0.2	0.2	0.2	0.2	0.2
Total Operations	1.7	1.6	1.5	1.5	1.9	1.8
Repairs						
System	0.1	0.0	0.1	0.1	0.1	0.1
Substation	0.4	0.5	0.4	0.3	0.4	0.4
Total Repairs	0.5	0.5	0.5	0.4	0.5	0.5
Management/Support Services	1.4	2.0	2.1	2.2	2.2	2.2
Total Transmission O and M	5.9	6.1	5.9	6.3	6.8	6.6

Source EPTI Application Schedule T-2.

EPTI forecast an adjusted total maintenance cost of $2.2 million for 1999 and $2.1 million for 2000. The 1999 and 2000 forecast amounts reflected several changes that were made to the components included in the maintenance cost category since the 1996 GTA Refiling.

These changes included organizational changes in EPTI's engineering and operations areas including the implementation of EPTI's Reliability Centered Maintenance (RCM) program. EPTI indicated that the majority of the transmission infrastructure was old; for instance, the average age of EPTI's 72 kV transmission facilities was approximately 33 years. To ensure that its facilities were effectively maintained while limiting maintenance expenses to the greatest

extent practicable in the future, EPTI adopted a maintenance strategy based on an RCM approach. RCM used processes and activities which set the frequency of maintenance based on the condition of equipment rather than timing.

As well, EPTI noted the 1999 and 2000 forecast reflected an increase in the allocation of telecontrol maintenance costs from EPDI to EPTI of approximately $0.2 million due to the reclassification of telecontrol assets in accordance with the recently amended EU Act. Environmental expenses had also decreased by $0.1 million.

EPTI forecast an adjusted[247] system and substation operations cost of $1.9 million for 1999 and $1.8 million for 2000. The 1999 and 2000 adjusted forecast reflected an increased allocation of engineering and operational training expenses to EPTI, and an increase in the forecast of system trouble operation expenses, including field switching and control room operations and a savings from the Work Management System.

EPTI forecast repair cost of $0.5 million for both 1999 and 2000. These amounts were the same as the forecast repair cost in the 1996 GTA Refiling.

EPTI forecast management and support services cost of $2.2 million for both 1999 and 2000. The 1999 amount represented a $0.8 million increase from the 1996 GTA Refiling. The forecast amounts for 1999 and 2000 were, however, consistent with the 1996 and 1997 actuals and 1998 reforecast.

Other than comments about the general inflation assumptions and the compensation program, Intervenors noted only the costs associated with the annual conduct of the RCM.

Position of the FIRM Customers

FIRM Customers expressed concern about the prudence of EPTI implementing the RCM. The FIRM Customers suggested that EPTI would be committing in excess of $1.0 million to the program during the period 1996 through to 2000, $560,000 of which would be spent in 1998/99/2000 period. The FIRM Customers noted that EPTI expected benefits of $40–60,000 to accrue after implementation.[248]

In evaluating the prudence of this program, the FIRM Customers suggested the Board give consideration to experience of the other utilities, particularly, where TransAlta states:

> The most significant impact on transmission operating expenses has been the development and implementation of the RCM Program. Through this program, maintenance practices on virtually every piece of transmission equipment are

[247] Exhibit 8
[248] Tr. p.1208

reviewed and optimized. This program provides enhanced reliability at significantly lower cost than traditional time-based maintenance programs.[249]

While the FIRM Customers appreciate the differences inherent in the transmission component of each company, the FIRM Customers submitted EPTI failed to prove why it should obtain approval for expenditures returning only a negligible benefit to customers. Accordingly, the FIRM Customers submitted the Board should disallow the RCM costs for both test years.

Position of EPGI

EPTI noted the Intervenors questioned the benefits to be gained from EPTI's RCM program. EPTI provided a detailed analysis demonstrating the benefit that the RCM project would provide into the future by minimizing maintenance costs with respect to its aging transmission facilities.[250] EPTI pointed out that the analysis was conservative and, although net benefits from the program were not seen until 2002 onward, those benefits would continue for the life of the equipment being maintained. EPTI stated that there were other benefits from the RCM program which were not easily quantifiable such as increased system reliability resulting from the completion of reliability assessments which assisted in making better decisions with respect to replacing and refurbishing equipment.

EPGI also noted Intervenors questioned the level of saving projected for EPTI's RCM program vis-à-vis what appeared to be a greater impact projected by TransAlta with respect to TransAlta's RCM program. EPTI suggested that TransAlta included a number of different items in its analysis, such as business restructuring and new control centre technology, which likely made a contribution to reducing TransAlta's operating costs, but were not part of EPTI's RCM program.

Board Findings

The Board has reviewed the adjusted costs for transmission operations and maintenance and finds the costs reasonable. The Board further notes that Intervenors did not disagree with EPTI's adjusted operations and maintenance expenses except for those costs associated with the implementation of the RCM program.

With respect to the RCM program, the Board notes that all capital maintenance projects proposed by EPTI have been approved in Part 1-General, 3(b)(3), Transmission, Capital Additions. The Board accepts EPTI's strategy of using processes and activities to set the frequency of maintenance based on the condition of the equipment rather than timing. The Board approves EPTI's expenses associated with the implementation of the RCM program.

In the Incentive Compensation section of this Decision, the Board notes that an adjustment was made to the compensation program for both 1999 and 2000. The Board directs EPTI, in its

[249] Exhibit 13, s.3.2.1
[250] EAL-EPTI-51

refiling, to reduce the compensation program expenditures by $100,000 in each of 1999 and 2000.

The Board has summarized its findings in the table below:

EPTI OPERATING & MAINTENANCE COSTS
1999 – 2000
($million)

	1999			2000		
	As Filed	Board Adjustment	Board Approved	As Filed	Board Adjustment	Board Approved
Maintenance						
System	0.2		0.2	0.2		0.2
Substation	1.6		1.6	1.5		1.5
Telecontrol	0.4		0.4	0.4		0.4
Total Maintenance	2.2		2.2	2.1		2.1
Operations						
System	1.7		1.7	1.6		1.6
Substation	0.2		0.2	0.2		0.2
Total Operations	1.9		1.9	1.8		1.8
Repairs						
System	0.1		0.1	0.1		0.1
Substation	0.4		0.4	0.4		0.4
Total Repairs	0.5		0.5	0.5		0.5
Management/Support Services	2.2		2.2	2.2		2.2
Compensation Program	0.0	(0.1)	(0.1)	0.0	(0.1)	(0.1)
Total Transmission O and M	6.8	(0.1)	6.7	6.6	(0.1)	6.5

(2) Taxes Other Than Income Tax

EPTI forecast property tax costs of $3.1 million for 1999 and $3.2 million for 2000. EPTI noted these amounts were approximately the same as the 1996 GTA Refiling, the 1996 and 1997 actuals and the 1998 reforecast. EPTI explained the increase of $0.1 million from 1998 to 1999 and from 1999 to 2000 reflected forecast increases in property taxes by the City of Edmonton and the County of Leduc, based on discussions with the property tax assessors of these

municipalities. EPTI noted the increase also reflected a forecast increase of 1% in business taxes payable to the City of Edmonton based on discussions with the City.

EPTI explained the linear property tax for power utilities, was currently under review by the Province of Alberta. However, EPTI's 1999/2000 forecast did not include an adjustment for any increase which might occur in this type of property tax.

Intervenors did not take issue with respect to EPTI's forecast property taxes.

Board Findings

The Board notes that the City of Edmonton, for the years 1996 to 1998, had an average increase of 2.3% for property taxes and 1.4% for business taxes. The Board also notes that the County of Leduc, for the same period, had an average increase in property taxes of 1.0% and that the County does not levy a business tax.

The Board notes that the Province of Alberta has completed a review of the linear property tax which included a reassessment of the base cost values utilized and a reassessment of the treatment of underground conduit. The Board notes that the Province has changed the assessment methodology for underground transmission lines which affects EPTI. The Board notes EPTI's position that the impact of the new assessment is not significant enough to change EPTI's property tax forecast.

The Board considers EPTI's forecast property taxes as reasonable and notes that Intervenors did not object to the total amount requested. The Board approves the forecast amounts of $3.1 million and $3.2 million for 1999 and 2000 respectively, and the Board directs EPTI, in its refiling, to include these amounts.

(c) Depreciation

For 1999 and 2000, EPTI carried out a "Technical Update" of the depreciation rates currently in effect and proposed an improved method of tracking depreciation reserves. Depreciation expense for EPTI was forecast at $7.5 million in 1999 and $7.7 million in 2000. The following table provides a comparison of EPTI's forecast depreciation expense from 1996 to 2000.

Depreciation and Decommissioning Expense
($ million)

	1996 Refiling	1996 Actual	1997 Actual	1998 Reforecast	1999 Forecast	2000 Forecast
Depreciation	7.6	7.9	7.7	8.1	7.5	7.7

Source: Application Section 3.4.1.2.

A copy of the Technical Update was attached as Appendix "B" to the Application and the following is a summary of the key elements of the Technical Update:

- The depreciation parameters (projection curves, projection lives and future net salvage rates) used in EPI's 1996 Tariff Refiling were used in the Technical Update.
- Depreciation rates were updated to reflect updated composite service life statistics derived from the age distribution of surviving plants using forecast plant closing balances as of 31 December 1998.
- The average net salvage rates were updated to reflect a new weighting from actual and future retirement activity.
- The depreciation reserve for net salvage was split out from the depreciation reserve for the investment portion of all rate categories. This allows EPTI to more accurately track and adjust rates to correct for potential imbalances between the theoretical and recorded reserves relating to the original investment versus the net salvage.
- Reserve imbalances between the theoretical and recorded reserves for each original investment account and each net salvage group were calculated.
- The recorded reserve was redistributed across all primary accounts by setting the primary account balance equal to the theoretical reserve balance and then scaling this balance up or down by the ratio of the total recorded reserve to the total theoretical reserve for each account grouping.
- Rates for amortizing the remaining imbalances over the remaining life of the assets were calculated.

- The depreciation expense for 1999 and 2000 was calculated as the sum of the 1999 and 2000 whole life depreciation accrual for the original investment plus the whole life

accrual for net salvage plus the 1999 and 2000 portion of any amortized reserve imbalances stemming from the depreciation reserves for the original investments and net salvage.

EPTI noted that using the updated depreciation rates for the investment portion of each account and the updated net salvage rate for each grouping of plant accounts resulted in theoretical reserves that were approximately 10% less in 1999 and 10% less in 2000 than the recorded reserves.

The following tables provided a summary of the impact of the Technical Update on EPTI's forecast depreciation expense for 1999 and 2000.

Comparison of EPTI's Forecast Depreciation Expense in the 1996 Tariff Refiling and the 1999 Forecast ($ million)

	1996 Refiling	1999 Before Technical Update			1999 With Technical Update			Difference due to Technical Update
	Total	Accrual	Amort	Total	Accrual	Amort	Total	Change
Transco								
Investment		6.2	(0.3)	5.9	5.7	(0.3)	5.4	
Salvage		(0.3)	0.0	(0.3)	0.2	0.0	0.2	
Total	6.5	5.9	(0.3)	5.6	5.9	(0.3)	5.6	0.0
General Plant	1.2	1.9	0.8	2.7	1.7	0.2	1.9	(0.8)
Total Transco	7.6	7.8	0.5	8.3	7.6	(0.1)	7.5	(0.8)

Source: Application Table 7

3. EPTI
(c) Depreciation

Comparison of EPTI's Forecast Depreciation Expense in the 1996 Tariff Refiling and the 2000 Forecast ($ million)								
	1996 ReFiling	2000 Before Technical Update			2000 With Technical Update			Difference due to Technical Update
	Total	Accrual	Amort	Total	Accrual	Amort	Total	Change
Transco								
Investment		6.4	(0.3)	6.1	5.8	(0.3)	5.5	
Salvage		(0.3)	0.0	(0.3)	0.2	0.0	0.2	
Total	6.5	6.1	(0.3)	5.8	6.0	(0.3)	5.7	(0.1)
General Plant	1.2	1.7	0.8	2.5	1.7	0.3	2.0	(0.5)
Total Transco	7.6	7.8	0.5	8.3	7.7	(0.1)	7.7	(0.6)

Source: Application Table 8

Position of EPTI

EPTI submitted the tables above indicated the impact of the technical update on the overall EPTI depreciation expense for both 1999 and 2000 was immaterial. EPTI suggested the depreciation expense for direct EPTI assets remained relatively flat, which was in keeping with a stable asset base. EPTI noted the depreciation expense for allocated general plant assets declined by $0.5 million between 1998 and 1999 (and then remained stable between 1999 and 2000). EPTI submitted this reduction in depreciation was the result of the combination of the 1999 Technical Update impact on the deprecation rates of general plant and the changes in the general plant allocation factors between 1998 and 1999.

EPTI noted that the Intervenors did not file evidence that took issue with EPTI's depreciation expense during the proceedings, in argument or in reply.

Board Findings

The Board accepts EPTI's evidence that the depreciation parameters (projection curves, projection lives and future net salvage rates) used in the 1996 Tariff Refiling were used in the Technical Update. The Board considers this update to depreciation expense to be a normal practice and within the bounds of a "Technical Update." Accordingly, the Board approves EPTI's forecast depreciation expense arising from the Technical Update.

For the same reasons as set out in the EPGI section on Depreciation, the Board accepts EPTI's proposal to redistribute the depreciation reserve and to segregate the net salvage reserve from the investment portion of the depreciation reserve.

3. EPTI
(c) Depreciation

For the same reasons as set out in the EPGI section on Depreciation, the Board considers that the 5% threshold for amortization of depreciation reserve imbalances should be employed for all accounts except the Rossdale plant accounts.

Accordingly, the Board directs EPTI, in its refiling, to:

- Adjust the EPTI depreciation expense in each of the years 1999 and 2000 to reflect the Board's findings that the 5% threshold for amortization of depreciation reserve imbalances applies for all transmission accounts.

4. SUMMARY OF BOARD DIRECTIONS

This section is a summary[251] of Board directions to EPGI/EPTI in this part. The Directions in *italics* are to be complied with in the 1999 refilings. The remaining directions are to be complied with in the future or at the time of the next GTA.

1. *The Board notes the FIRM Customers' conclusion that the IS allocation factors, determined by EPGI/EPTI in response to MI.EPGI-16(b), were not used for allocating IS operating costs. The Board also notes EPGI/EPTI's acknowledgement that the allocation error would be corrected in the refiling. The Board accepts the explanation and the Board directs EPGI/EPTI to apply the determined ratios in the refiling.* [Section 1(b)]

2. *Accordingly, the Board directs EPGI/EPTI, in their refilings, to apply the methodologies for allocating common costs, as presented in the Application.* [Section 1(b)]

3. *The Board directs EPGI, in its refiling, to make the following changes:*

   - *Reduce the labour portion by $0.25 million in 1999 and $0.50 million in 2000.*
   - *Reduce the salary portion by $0.25 million in 1999 and $0.15 million in 2000.*
   - *Reduce "at-risk" compensation by $0.2 million in 1999 and $0.15 million in 2000.*

   [Section 1(c)]

4. *Accordingly, the Board directs EPGI, in its refiling to reduce labour, salary and "at-risk" compensation by $0.7 million in 1999 and $0.8 million in 2000.* [Section 1(c)]

5. *The Board considers that the need for the increase has not been demonstrated and, therefore, the Board directs EPTI, in its refiling, to reduce the 'at-risk' compensation by $0.1 million in each of 1999 and 2000.* [Section 1(c)]

6. The Board directs EPGI, in any application for a TSR, to include adjustments that are consistent with the methodology approved by the Board in the section of this Decision dealing with AE's Reserve for Injuries and Damages. [Section 1(d)]

7. The Board directs EPGI to apply to the Board for final disposal of the closing balance of the self-insurance reserve as at 31 December 2000. At the time of the application, the Board will review the charges to the self-insurance reserve and approve the disposition of any remaining balances to the Balancing Pool. [Section 1(d)]

[251] This summary has been prepared for the convenience of all parties. The directions in the main body of the Decision shall prevail over this summary if there are any differences.

8. *Accordingly, the Board directs EPGI, in its refiling, to include a hearing cost provision of $515,000 for 1999 and $516,000 for 2000.* [Section 1(e)]

9. Accordingly, the Board directs EPGI to transfer any residual balance, whether positive or negative, in the EPGI Hearing Cost Reserve at the end of 2000 to the EPTI Hearing Cost Reserve. [Section 1(e)]

10. *The Board directs EPGI/EPTI, in their refilings, to capitalize the Y2K costs to rate base in 2000 and to amortize those costs according to the asset for which the Y2K costs were incurred.* [Section 1(f)]

11. *The Board directs EPGI and EPTI, in their refilings, to continue to credit the decommissioning funds supplied by customers at the composite rate of return to reflect the above Board findings.* [Section 1(g)]

12. *For the reasons set out above, the Board directs EPGI, in its refiling, to reduce capital expenditures with respect to the Genesee black start project for the year 2000 by $2.2 million.* [Section 2(a)(1)(D)]

13. *Accordingly, the Board directs EPGI, in its refiling, to remove $12 million from 1999 capital expenditures.* [Section 2(a)(1)(E)]

14. *Accordingly, the Board directs EPGI, in its refiling, to remove $0.6 million from 1999 and $1.1 million from 2000 the capital expenditure category entitled "projects less than $1.0 million."* [Section 2(a)(1)(F)]

15. *The Board directs EPGI, in its refiling, to reduce the Clover Bar plant balance by $3.0 million effective 1 January 1999.* [Section 2(a)(1)(G)]

16. Further the Board directs that any future recovery resulting from a favourable ruling will be to the benefit of the shareholders account. [Section 2(a)(1)(G)]

17. *For all of the above reasons, the Board directs EPGI, in its refiling, to use a 36.6 day expense lag for other operating expenses in the calculation of necessary working capital for 1999 and 2000.* [Section 2(a)(2)(A)]

18. *Accordingly, the Board directs EPGI, in its refiling, to deem a quarterly payment of dividends in the calculation of necessary working capital for 1999 and 2000.* [Section 2(a)(2)(B)]

19. *Therefore, the Board directs EPGI, in its refiling, to use the lead/lag days as calculated for the remaining components of necessary working capital for 1999 and 2000.* [Section 2(a)(2)(D)]

4. SUMMARY OF BOARD DIRECTIONS

20. *The Board notes that EPGI has been directed to make changes to the costs in each expense category. The Board directs EPGI, in its refiling, to revise the 1999 and 2000 necessary working capital using the Board approved costs in each expense category.* [Section 2(a)(2)(D)]

21. *Therefore, the Board directs EPGI, in its refiling, to remove the minimum return margin for Clover Bar and Rossdale for 1999 and 2000.* [Section 2(b)]

22. *Accordingly and for purposes of this Decision, the Board directs EPGI, in its refiling, to include a dragline operating benefit of $1.6 million for 1999 and $1.7 million for 2000. The amounts should be clearly shown as a cost of coal in the refiling.* [Section 2(c)(1)(C)]

23. *The Board directs EPGI, in its refiling, to reduce Royalties and Other by $0.2 million in each of 1999 and 2000.* [Section 2(c)(3)(A)(ii)]

24. *The Board directs EPGI, in its refiling, to reduce the expenses associated with office and general by $0.25 million in each of 1999 and 2000.* [Section 2(c)(4)(A)]

25. *Therefore, the Board directs EPGI, in its refiling, to reduce the costs associated with the overhaul of boiler auxiliaries by $0.3 million in 1999.* [Section 2(c)(4)(B)]

26. *Therefore, the Board directs EPGI, in its refiling, to reduce the 1999 regular maintenance forecast for Rossdale by $800,000 ($2.4 million less $1.6 million) and for 2000 by $700,000 ($2.3 million less $1.6 million).* [Section 2(c)(4)(B)]

27. *Therefore, the Board directs EPGI, in its refiling, to include only $0.3 million of the $0.6 million requested increase for 1999.* [Section 2(c)(4)(C)]

28. *Accordingly, the Board directs EPGI, in its refiling, to allocate an equal amount of the allowed decommissioning costs to 1999 and 2000.* [Section 2(d)(1)(B)]

29. *Therefore, the Board directs EPGI, in its refiling, to reduce the 1999 and 2000 Rossdale depreciation expense to reflect a reduction of $8.0 million in forecast decommissioning costs.* [Section 2(d)(1)(D)]

30. Accordingly, the Board directs EPGI to identify any additional Rossdale decommissioning costs incurred as a result of the construction of any non-regulated unit(s) and subtract such costs from the actual decommissioning costs when making an application under section 42 of the GUR to collect or refund any differences between actual and collected decommissioning costs. [Section 2(d)(1)(D)]

31. *Accordingly, the Board directs EPGI, in its refiling, to recalculate its depreciation expense using the 5% threshold for amortization of depreciation reserve imbalances for all accounts except the Rossdale plant accounts.* [Section 2(d)(2)(B)]

4. SUMMARY OF BOARD DIRECTIONS

32. *The Board directs EPGI, in its refiling, to:*

- *Reduce the forecast decommissioning expense for Rossdale by $5.823 million to reflect the error identified in Exhibit 8.*
- *Reduce the forecast decommissioning expense for Rossdale by a further $8.0 million to reflect the Board's findings in the Rossdale Decommissioning section of this Decision.*
- *Adjust the depreciation expense for Rossdale such that equal amounts of allowed investment accruals and equal amounts of allowed decommissioning costs are allocated to 1999 and 2000.*
- *Reduce the forecast decommissioning expense for Clover Bar by $2.333 million to reflect the error identified in Exhibit 8.*
- *Reduce the depreciation expense by $0.255 million (adjusted by the effect, if any, of Rossdale) in each of the years 1999 and 2000 to reflect the Board's findings that the 5% threshold for amortization of depreciation reserve imbalances applies for all accounts except the Rossdale plant accounts.* [Section 2(d)(2)(E)]

33. *Therefore, the Board directs EPTI, in its refiling, to adjust the lag days on operating expenses to reflect the time between rendering of service and the issue date of suppliers' invoice for 15 days.* [Section 3(a)]

34. *Further, the Board directs EPTI, in its refiling, to deem a quarterly payment of dividends in the calculation of necessary working capital.* [Section 3(a)]

35. *Therefore the Board directs EPTI, in its refiling, to use the lead/lag days as calculated for the remaining components of necessary working capital for 1999 and 2000.* [Section 3(a)]

36. *The Board directs EPTI, in its refiling, to revise the 1999 and 2000 necessary working capital using the Board approved costs in each expense category.* [Section 3(a)]

37. *The Board directs EPTI, in its refiling, to reduce the compensation program expenditures by $100,000 in each of 1999 and 2000.* [Section 3(b)(1)]

38. *The Board approves the forecast amounts of $3.1 million and $3.2 million for 1999 and 2000 respectively, and the Board directs EPTI, in its refiling, to include these amounts.* [Section 3(b)(2)]

39. *The Board considers EPTI's forecast property taxes as reasonable and notes that Intervenors did not object to the total amount requested. The Board approves the forecast amounts of $3.1 million and $3.2 million for 1999 and 2000 respectively, and the Board directs EPTI, in its refiling, to include these amounts.* [Section 3(b)(2)

4. SUMMARY OF BOARD DIRECTIONS

40. Accordingly, the Board directs EPTI, in its refiling, to:

- *Adjust the EPTI depreciation expense in each of the years 1999 and 2000 to reflect the Board's findings that the 5% threshold for amortization of depreciation reserve imbalances applies for all transmission accounts.* [Section 3(c)]

5. ORDER

THEREFORE, IT IS ORDERED THAT:

(1) EPCOR Generation Inc. and EPCOR Transmission Inc. shall refile their 1999/2000 General Tariff Applications, on or before 16 December 1999, incorporating the findings of the Board in this Decision respecting EPGI, EPTI, TransAlta and the AE Negotiated Settlement as approved in Decision U99046.

(2) EPCOR Generation Inc. in its refiling, shall include all of the supporting schedules necessary for the Board to make its final determination respecting (i) EPGI's 1999/2000 Phase I revenue requirement and (ii) 1999/2000 GENCO reservation prices and UOPs. The refiling shall be at a level of detail sufficient to reconcile with the original filing and demonstrate compliance with the Board's findings.

(3) EPCOR Generation Inc., in its refiling, shall identify the quantum of adjustments arising from differences between existing and final 1999 GENCO reservation prices and propose a method of collecting or refunding the adjustments.

(4) EPCOR Transmission Inc., in its refiling, shall include all of the supporting schedules necessary for the Board to make its final determination respecting (i) EPTI's 1999/2000 Phase I revenue requirement and (ii) 1999/2000 TRANSCO tariffs. The refiling shall be at a level of detail sufficient to reconcile with the original filing and demonstrate compliance with the Board's findings.

(5) EPCOR Transmission Inc., in its refiling, shall identify the quantum of adjustments arising from differences between existing and final 1999 TRANSCO tariffs and propose a method of collecting or refunding the adjustments.

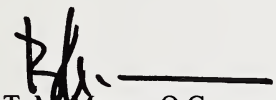
5. ORDER

Dated in Calgary, Alberta, on 25 November 1999.

ALBERTA ENERGY AND UTILITIES BOARD



N. W. MacDonald, P.Eng.
Presiding Member



B. T. McManus, Q.C.
Member



A. J. Berg, P.Eng.
Member

Part 4 - TAU

TABLE OF CONTENTS

1. GENERAL 609

(a) Software Development Additions 609

(1) Software Development (Undefined and Year 2000 Projects) 609

(2) Industrial Customer Billing System 611

(3) SAP Net Pay Module 611

(4) Customer Billing System 612

(5) Amortization Period 614

(b) Corporate Capital Additions 615

(1) Information Technology Hardware 615

(2) Calgary Head Office 617

(3) Sale of High River Service Centre 622

(4) Sustainable Development 629

(5) SD Projects 631

(6) Automated Mapping/Facilities Management 633

(c) Corporate Operating Expense 635

(1) Labor and Materials Escalation 635

(2) Telecommunication Expense 635

(d) Allocation of Common Costs 638

(e) Incentive Compensation 642

(f) Income Tax 644

(1) Income Tax Methods 644

(2) Currently Approved Method 646

(3) TransAlta's Proposed Method 647

(g) Hearing Cost Reserve 651

(h) Pension Reserve 653

(i) Self-Insurance Reserve 664

(j) Depreciation 672

Part 4 – TAU

TABLE OF CONTENTS

1. GENERAL 609

(a) Software Development Additions 609

(1) Software Development (Undefined and Year 2000 Projects) 609

(2) Industrial Customer Billing System 611

(3) SAP Net Pay Module 611

(4) Customer Billing System 612

(5) Amortization Period 614

(b) Corporate Capital Additions 615

(1) Information Technology Hardware 615

(2) Calgary Head Office 617

(3) Sale of High River Service Centre 622

(4) Sustainable Development 629

(5) SD Projects 631

(6) Automated Mapping/Facilities Management 633

(c) Corporate Operating Expense 635

(1) Labor and Materials Escalation 635

(2) Telecommunication Expense 635

(d) Allocation of Common Costs 638

(e) Incentive Compensation 642

(f) Income Tax 644

(1) Income Tax Methods 644

(2) Currently Approved Method 646

(3) TransAlta's Proposed Method 647

(g) Hearing Cost Reserve 651

(h) Pension Reserve 653

(i) Self-Insurance Reserve 664

(j) Depreciation 672

1. GENERAL

(a) Software Development Additions

In its Application TransAlta requested approval for Software Development Additions in the amount of $10.0 million for 1999 and $18.0 million for 2000 (See Table below).

TransAlta Software Development Additions ($Millions)		
	1999	2000
Software Development		
Undefined Projects	3.0	8.0
Year 2000 Project	2.2	0.0
Industrial Customer Billing System	2.2	0.0
SAP Net Pay Module[252]	2.6	0.0
Customers Billing System[253]	0.0	10.0
Total	10.0	18.0

The issues that arose during the proceeding pertaining to individual items included in the Software Development Additions are addressed below.

(1) Software Development (Undefined and Year 2000 Projects)

Position of TransAlta

TransAlta provided for $3.0 million in 1999 and $8.0 million in 2000 for undefined IT projects that will be implemented to continuously improve corporate productivity. The 1999 amount for undefined projects takes into account that specific software development projects have been identified for that forecast year.[254]

TransAlta considered that the introduction of new software technology makes improvements to corporate productivity possible.

TransAlta stated that it examined historic spending trends to arrive at the forecast costs for computer software development. TransAlta also stated that a number of major software upgrades and development projects were deferred into the year 2000 because of initiatives to prepare for Y2K.[255] TransAlta increased its forecast expenditures for the year 2000 for the anticipated

[252] SAP Development is being developed over two years (i.e. $0.6 million in 1998 and $2.0 million in 1999) and added to rate base in 1999.

[253] The Customer Billing System – Retail Customers, is being developed over two years (i.e. $5 million each for 1999 and 2000) and added to rate base in 2000.

[254] Application Section 5.2

[255] IPCAA.TAU-18

upgrades. The upgrades were not undertaken to prepare for the "New World" as new software will have to be developed to accommodate future industry change.

TransAlta disagreed with the FIRM Customers submission that the undefined projects of $3 million in 1999 and $8 million in 2000 are not justified based on historic trends, particularly if the Business Integrated Solutions Initiatives (BISI) project is excluded, as it was not considered a typical project.

TransAlta responded that considerable resources were allocated to the Y2K initiatives and that those resources are now available for other required projects. TransAlta submitted that projects, which were undefined at the time of filing, would be required to ensure TransAlta is able to continue to provide the current level of service in the future. The amortization for these projects amounts to $0.1 million in 1999 and $1.2 million in 2000.

Position of the FIRM Customers

The FIRM Customers stated that the forecasts for undefined projects seem to be based on historic trends. TransAlta provided the following information to the FIRM Customers request of historical spending for the period 1990-97 recorded and 1998 forecast for the type of projects that make up the historic trend.[256]

1996	BISI Project	$18 million
1997	Software Projects less than $1.0M	$ 3 million
1998	Y2K Software, Assets Accounting	$ 6.7 million

Mr. Janke acknowledged the 1996 BISI Project was not a typical software development project.[257] He also described the 1998 Y2K Software Project as an "unusual requirement."

The FIRM Customers submitted the historical information does not justify the amount requested for the test years.

Board Findings

The Board considers that during the transition to a deregulated electric industry certain provisions for software changes and upgrades are necessary as legislation and regulations affect the manner in which the utilities do business. The Board also considers that historical spending in a project-oriented area like software development will likely vary depending on the number of years considered and the scope of the individual projects.

TransAlta has forecast $3.0 million for undefined projects for 1999, a year for which TransAlta has forecast specific software projects and $8.0 million for undefined projects for 2000, a year

[256] FIRM.TAU-63(c)
[257] Tr. p.2542

for which specific projects have not yet been identified. The Board notes that the 1999 forecast for specific projects amounted to $7.0 million for a total defined and undefined forecast of $10.0 million including theY2K project. The Board considers that since specific projects have not been identified for 2000, the $8.0 million forecast should be viewed in relation to the 1999 forecast of total defined and undefined projects of $7.8 million excluding the Y2K project.

Therefore, the Board will accept TransAlta's forecast of undefined software projects as filed for the year 1999 and 2000 and will also accept the $2.2 million expenditure for theY2K project.

(2) Industrial Customer Billing System

Position of TransAlta

TransAlta forecast $2.0 million[258] in 1999 to replace the current system which was commissioned in the mid-1980s. TransAlta stated that the existing system would not accommodate changes resulting from restructuring. In particular the existing system does not have the capability to separate invoicing between wires-related tariffs and energy consumption. The existing system was written in an obsolete computer language. Routine tasks such as rate changes had become cumbersome because of the complexity of the program and lack of knowledgeable resources.[259]

Position of the Intervenors

Intervenors did not address the $2.0 million forecast expenditure to replace the existing Industrial Customer Billing System.

Board Findings

The Board accepts TransAlta's position that the Industrial Customer Billing System should be replaced for the reasons stated by TransAlta. The Board approves the $2.0 million expenditure in 1999 to replace this system. The Board notes that $0.2 million is for work completed in 1998 for a total addition of $2.2 million added to rate base in 1999.

(3) SAP Net Pay Module

Position of TransAlta

TransAlta proposed a capital expenditure of $2.0 million in 1999 to implement the SAP Net Pay Module that was not available when SAP was originally implemented. The existing net pay system (CYBORG) is not Y2K compliant.

---

[258] TransAlta also forecast an expenditure of $150,000 in 1998 for a total of $2.2 million in 1999.
[259] Application Section 5.2

TransAlta also proposed to modify the current SAP financial reporting systems to meet revised requirements for external financial reporting. The current configuration in SAP does not meet revised statutory segmented financial reporting requirements.[260]

In respect of the SAP development, TransAlta stated that it is necessary to upgrade the system to meet statutory financial reporting requirements, as the existing system does not conform to this need. Further, the existing HR Net Payroll system is not Y2K compliant and implementing the SAP Net Payroll system will allow TransAlta to build on the investment in SAP and minimize future support costs.

Position of the Intervenors

Intervenors did not address the $2.0 million forecast expenditure for the SAP Net Pay Module.

Board Findings

The Board notes that TransAlta's reason for the SAP Net Pay Module is to replace a non-Y2K system with one that is Y2K compliant and to meet revised external financial reporting requirements. The Board considers that the expenditure is necessary under the circumstances.

The Board therefore accepts TransAlta's forecast of $2.0 million for the SAP Net Pay Module development as filed.

(4) Customer Billing System

Position of TransAlta

TransAlta proposed a new customer billing system and forecast $5.0 million for 1999 and $5.0 million for 2000 to implement the new application. TransAlta stated that the current system (CUBIS) was commissioned in 1990 and will not accommodate changes resulting from the restructuring of the utility industry. The current system does not accommodate invoicing for wires-related tariffs, and does not provide customers with flexible billing options such as the Regulated Rate Option.

The current system is eight years old and was also written in an obsolete computer language and suffers from the same complexities as the Industrial Customer Billing System.[261]

The new Customer Billing System is scheduled for implementation sometime in the year 2000 which will address new billing issues and provide the ability to continue current applications. TransAlta considered this would minimize ongoing support costs.

[260] Application Section 5.2
[261] Application Section 5.2

TransAlta stated that the FIRM Customers' recommendation that the unamortized balance spent on CUBIS in 1995 to 1996 be retired and written off without further amortization or expense to ratepayers was without merit. The CUBIS expenditures were related to new functionality required as a result of the new industry structure. Further, as set out in FIRM.TAU-65, there was no unamortized balance related to CUBIS as of January 1998.

TransAlta submitted that its forecast cost for computer software is reasonable.

Position of the FIRM Customers

The FIRM Customers stated that despite $3.6 million in extensive upgrades and improvements to CUBIS in 1995-1996, TransAlta now claims the existing CUBIS system is "unsupportable due to obsolete language, technology, and interfaces. CUBIS is also incapable of supporting the unbundling of rates required for restructuring."[262] TransAlta is now requesting $10 million for a new CUBIS system. The FIRM Customers considered the prior expenditure of $3.6 million will now be stranded and such an outcome is unreasonable. The Utility knew in 1995 restructuring was coming and changes in its billing system would be required. Further, if CUBIS were written in an obsolete language, the $3.6 million additional investment would seem to have been imprudent.

The FIRM Customers submitted that TransAlta is preparing for competition by creating a state-of-the-art billing system for its profit in a deregulated retail environment; but having it paid for at current ratepayers' expense (e.g. Marcus at Tr. p.5226). The FIRM Customers recommended the Board direct the unamortized balance spent on CUBIS in 1995-1996 be retired and written off without any further amortization or expense to ratepayers.

Board Findings

The Board notes the concern of the FIRM Customers that the $3.6 million additional investment would seem to have been imprudent. The Board notes the additional expenditure resulted in an extension to the life of CUBIS. The extension saved consumers the cost of a new system at an early stage in the industry restructuring that might also have been obsolete in 1999. The Board considers the life extension was to the benefit of consumers. Therefore, the Board does not find that TransAlta was imprudent by extending the life of CUBIS.

In respect of the FIRM Customers claim that TransAlta is creating a state-of-the-art billing system for its profit in a deregulated environment and paid for by current customers, the Board notes Mr. Janke's comments at Tr. p.3724:

> My understanding is that the billing system that we are putting in for the smaller customers where we have many transactions to process, that that wouldn't be

[262] FIRM.TAU-64 (b)

capable of looking after the new retail world without some further modifications or enhancements to it.

If that did indeed materialize, I'm sure there would have to be some thought given to how do you do an appropriate allocation of those costs at that time.

The Board considers there is no evidence on the record to substantiate the FIRM Customers' claim.

The Board, therefore, accepts TransAlta's forecast of $10.0 million for its new customers billing system as filed.

(5) Amortization Period

Position of TransAlta

TransAlta responded to the FIRM Customers recommendation that the amortization period for billing systems should be extended from 5 to 10 years. TransAlta stated that the industrial billing system is just a combination of manual entry and spreadsheets that is approximately 15 years old and submitted that the manual use of continually evolving spreadsheets does not provide any evidence that a purchased billing package would have a useful life of 10 years.

With respect to CUBIS, it was only the additional expenditures in the 1995/1996 period that allowed CUBIS to reach a nine-year life. Actual experience demonstrated that the initial CUBIS investment only had a useful life of approximately five years. TransAlta submitted that there is no evidence to support the FIRM Customers position that billing packages have a useful life of 10 years and TransAlta submitted that the Board should confirm its current practice of amortizing such software over a five-year period.

Position of the FIRM Customers

In Decision U97065, page 473, the Board stated "the amortization of major software projects should reflect their useful lives." Specifically, at that time, the Board ordered TransAlta to use a 10-year amortization period for the BISI system. This system encompasses modules for financial accounting, cost control, material management, human resources, plant maintenance, sales and distribution, and information and work management.[263]

TransAlta proposed that two major software systems be amortized over only a 5-year period, namely the Industrial Customer Billing System ($2.1 million) and the Customer Billing System ($10 million).[264] Both systems are designed to accommodate billing changes due to restructuring.

[263] Decision U97065, p.470
[264] FIRM.TAU-62

The FIRM Customers considered that since the existing industrial billing system was developed in the mid-1980's, and the existing customer billing system (CUBIS) originated in 1990, both systems reflected close to a 10-year life. The FIRM Customers argued that the Board previously found that an amortization period of 10-years was appropriate for the BISI system and the same amortization period would be appropriate for the new systems.

Board Findings

The Board considers that utility billing systems are not comparable to systems such as the BISI system. The BISI system is a corporate information and management system that includes the information from the billing systems. The restructuring of the electric industry in Alberta places the billing systems in a changing environment and ever changing technology that is not amenable to extended software life beyond five years.

The Board, therefore, confirms its current practice of amortizing software over a five-year period or over its useful life if the life of the software is expected to be greater than five years. The Board directs TransAlta, in its next GTA filing, to specify the anticipated useful life of any capital enhancements to software systems included in the application.

(b) Corporate Capital Additions

In its Application TransAlta requested approval for Corporate Capital Additions in the amount of $23.0 million for 1999 and $27.9 million for 2000. The issues that arose during the proceeding pertaining to individual items included in the Corporate Capital Additions are addressed below.[265]

(1) Information Technology Hardware

The concern raised in respect of Information Technology (IT) Hardware was the need to replace all the computer requirements at one time and that the timing of the replacement appears to charge current customers for costs that should be included in the PPA process.

Position of TransAlta

TransAlta proposed to replace its aging IT infrastructure to meet ongoing business requirements. The reason given for the proposal was that existing equipment will not support new applications, failure rates are increasing and most desktop and server hardware are past the 3-year warranty period. As well, the increasing failures add to operating costs. TransAlta also stated that new technologies now available cost less to support.

[265] Application Section 5.2

TransAlta provided the forecast cost of the IT infrastructure replacement in the Corporate Services CWIP Continuity schedules for 1999 and 2000 as follows:

Forecast	1999	2000
IT Hardware ($ millions)	11.5	5.0

(Application Section 5.2)

Details of the IT infrastructure cost were provided in FIRM.TAU-70.

TransAlta stated that to upgrade the infrastructure on a piece meal basis would create a non-standard system and lead to increased capital and operating costs. TransAlta submitted that the proposal is just and reasonable.

TransAlta disagreed with the FIRM Customers' submission that the replacement of the computers need not be done at once and that a portion could be deferred. TransAlta considered that it is not practical to have a percentage of computers replaced with current technology only to be incompatible with the old computers (see section 5.2 of Application, AFE for IT Hardware). Further, to ensure computers are fully compatible both within TransAlta and with external contacts, the replacement is required. TransAlta submitted that the complete replacement is required and is reasonable.

Position of the FIRM Customers

The FIRM Customers did not question the need to replace the IT infrastructure, most of which was purchased in 1996. However, the need to replace all of TransAlta's computers at the same time was questioned. The FIRM Customers suggested that at least a portion of the computer requirements could be deferred. As well, the FIRM Customers considered that there is a clear implication TransAlta is attempting to replace or refurbish many of its operating assets (at the expense of current customers) in anticipation of the PPA process.

None of the other Intervenors had any major concerns with respect to TransAlta's capital expenditures for the replacement of the IT infrastructure.

Board Findings

The Board considers that TransAlta has two strategies it can follow to replace IT infrastructure. One is to replace a portion of the infrastructure each year on an ongoing basis and the other is to do a complete replacement at one time. The Board considers that the net effect of either approach should be the same and that a three-year rotation is reasonable. The Board notes the statement of the FIRM Customers that the last time TransAlta replaced most of its IT Hardware was in 1996.

The Board accepts that the replacement at one time is appropriate given that the last change was in 1996. The Board approves the IT infrastructure capital expenditure for 1999 and 2000 as filed.

(2) Calgary Head Office

Position of TransAlta

TransAlta forecast three projects for its Head Office complex for 1999 and 2000 as follows:

	1999	2000
Calgary Master Plan	$8,016,000	$4,457,200
Head Office Mechanical Systems	$898,000	$1,382,800
T3 Training and Disaster Recovery Centre	$1,175,000	
Total	**$10,089,000**	**$5,840,000**

The Calgary Master Plan and the T3 Training and Disaster Recovery Centre also had forecast expenditures for 1998 in the amount of $155,000 and $150,000 respectively.

Calgary Master Plan

TransAlta justified the expenditure for the Calgary Master Plan by stating that many of the mechanical and electrical systems in T1 have outlived their useful life. If changes were not made, worker productivity would be impacted due to poor air quality and thermal comfort. There is also the potential for power outages and damage to office equipment. Ventilation problems are getting worse and make it extremely difficult to control building temperature. The changes to the T1 building provide the opportunity to change the floor plans for better space utilization and house all of Head-Office staff in owned buildings.

TransAlta stated that at least ten different scenarios were considered, and the proposed recommendation was the most cost efficient one.[266]

Operating costs would also decrease because additional lease space would no longer be required (Centre 12). The higher occupancies would require more cooling/ventilation and power, resulting in upgrades to the T2 mechanical/electrical systems as well.

TransAlta responded to IPCAA's submission that TransAlta could sell one or more of its business units. IPCAA submitted that it is inappropriate for TransAlta to ask current customers to pay for this kind of expense during the transition to competition when it is unclear which customers, if any, might benefit from the project. TransAlta submitted that there is no evidence that TransAlta is planning to sell one of its business units.

TransAlta submitted that the Head Office Master Plan is required, reasonable and does not represent duplication of any other AFEs included in the filing.[267]

---

[266] Undertaking at Tr. p.2553 (Exhibit 92)
[267] Tr. p.2327-2334

Head Office Mechanical Systems

TransAlta considered the expenditure is justified because of the need that mechanical systems in the Head Office Complex must continually be updated to maintain current operations. Equipment must be replaced/rebuilt as it reaches the end of its life. Systems must be upgraded/optimized in order to provide a safe, healthy and comfortable work environment. Over time, systems must also be modified to meet the changing needs of the building occupants and changes in energy rates.

T3 Training and Disaster Recovery Centre

TransAlta justified the expenditure for the T3 building by stating that it would make a perfect training and disaster recovery facility because of its proximity to and operating isolation from the rest of the Head Office Complex. The facility is easily accessible from Head Office and could be maintained and serviced by current staff and contractors. Another advantage was that the building could be operated independently of Head Office, an important feature for disaster recovery.

The current training and disaster recovery facility, located on the second floor at Centre 12, is only temporary and far from ideal. Building systems in a rented facility are not within TransAlta's control and are not reliable enough for a disaster recovery facility.

Position of the Intervenors

IPCAA considered that the Calgary Master Plan and the Head Office Mechanical Systems were similar, and the way the proposals were justified was misleading. Whether intentionally or otherwise, the Calgary Master Plan AFE conveys the impression that the proposed expenditures are required to remedy problems associated with the mechanical and electrical systems in the T1 and T2 buildings. IPCAA questioned TransAlta's position that the purpose of the Calgary Master Plan was to ensure that TransAlta employees would have adequate air quality and thermal comfort. IPCAA stated that is what the Head Office Mechanical systems project is intended to accomplish. IPCAA further considered Mr. Janke's statement that the concerns about worker productivity being negatively impacted due to poor air quality and thermal comfort are not the "... biggest driver behind making changes to the head office master plan."[268] IPCAA stated that the Calgary Master Plan is really about renovating office space. IPCAA submitted TransAlta has failed to discharge its onus of justifying the expenditure.

IPCAA was also concerned that TransAlta is planning to spend significant amounts to improve the working environment in buildings that may not be used to provide services to some current customers in the near future. TransAlta could in fact sell one or more of its business units in

[268] Tr. p.2332

which case the need for and use of these buildings could change significantly.[269] IPCAA stated that it is entirely inappropriate for TransAlta to ask current customers to pay for this kind of expense during the transition to competition when it is unclear which customers, if any, might benefit from the project. IPCAA submitted that the Calgary Master Plan project should be excluded from the 1999 and 2000 TransAlta revenue requirements.

Board Findings

The Board considers that two issues were raised during the proceeding. The first issue is the possible duplication of expenditures contained in the Calgary Master Plan and the Head Office Mechanical systems. The second issue is the timing of the expenditures in 1999 and 2000 when the next step in the deregulation process is 2001. Intervenors felt that current customers would be paying for expenses they may never use, or TransAlta could sell one of its business units leaving customers to pay the remaining costs.

With respect to the possible duplication of expenditures contained in the Calgary Master Plan and the Head Office Mechanical systems, the Board notes the response at Tr. p.2329-2330:

> There is no duplication between the two AFEs that you have referred to. There is a mechanical component that is associated with the head office master plan. It is different equipment, though, that would be worked on in the head office master plan as opposed to the head office mechanical system AFE.
>
> The head office mechanical systems are those facilities that we would be replacing on our normal replacement-type schedule.
>
> ...
>
> On the head office master plan, there is mechanical work that is planned for there as well, but it is quite different in nature. For example, it would be installing a new return airshaft in T-1. It would be increasing the size of the return air fans. It would be changing the structure on all of the floors so that we have a different system of ducting and boxes within each of the floors themselves.
>
> So they both relate to mechanical work, but there is no duplication between the two.

The Board accepts that the Calgary Master Plan and the Head Office Mechanical systems AFEs are completely different in scope and intent. In terms of mechanical work, the Calgary Master

[269] See Exhibit 136, Vol. I, p. 2. It should be noted that TransAlta took no issue with this position in its Rebuttal Evidence (Exhibit 16). Neither was this aspect of the Drazen Consulting Evidence challenged by TransAlta through cross-examination.

Plan is a refit of the mechanical infrastructure whereas the Head Office Mechanical systems is a replacement program for existing equipment that is at the end of its useful life.

The Board accepts TransAlta's position that the Calgary Master Plan does not duplicate costs in the Head Office Mechanical systems project.

On the issue of the timing of the expenditures in 1999 and 2000 in advance of the next step in the deregulation process, the Board considers that the deregulation process has been ongoing since the enactment of the EU Act in 1995. The ongoing restructuring process has affected the manner in which the utilities do business.

In this respect the Board notes TransAlta's response at Tr. p.2330-2332:

> The head office master plan is intended to do more than just replace some of the mechanical systems that we have in our head office complex.
> What we have encountered over the last year or more is we have had some significant changes within our organization at TransAlta. We have had significant layoffs, voluntary retirements. We had a significant reorganization that took place in the middle of last year.
>
> What we have is, in many ways, what I would describe as Swiss cheese in our complex, pockets of empty space that we would like to recapture. We also have a lot of work areas where people now report to the same vice president, department head, or manager, and they would like to be able to get those work groups together for efficiency.
>
> We have a lease that is coming due from our Centre 12 complex that we lease from Great West Realty that comes due next year, and we just see this as an opportunity to be able to address all of those problems and those issues along with some of the mechanical problems that we have got which, over time, will continue to get worse.
>
> We expect that by going ahead with the head office master plan, we will be able to eliminate some nine floors -- or of the nine floors that we rent and lease in Centre 12, that we would be able to eliminate as much as seven of those floors by changing the density in our head office complex.
>
> We expect to have about a 15 percent improvement in the density, or another way of looking at that is the number of square feet per employee would be reduced by 15 percent making more effective use of the space that we have.
>
> So those are just some of the considerations that have gone into the head office master plan.

The Board considers that TransAlta's decision to implement the Calgary Master Plan is appropriate under the circumstances.

The Board also agrees with TransAlta that there is no evidence that TransAlta is planning to sell one of its business units and the Board considers that the Intervenors' statement is speculative.

Intervenors did not address the merits of the T3 Training and Disaster Recovery Centre project. The Board, on its own review, considers that due to the proximity and operation isolation of the facility from Head Office, the project has merit and is in the interest of customers. However, the Board notes that the choice between owning and leasing is primarily an economic decision and not an operational decision.

The Board's review of the Calgary Master Plan indicates that Corporate Office Expenses include $1.5 million in 1999 and $1.4 million in 2000 to support this project.[270] TransAlta explained the increase as follows:[271]

> That reference is in regards to the O & M expenses that we would be incurring during the project itself. And during that time period, there would be an increase in our operating expense. The major reason for the increase in cost is in respect of our move and renovation costs.
>
> We will basically be restacking the entire complex after we do some major work on the mechanical and electrical systems. So we will have to move our staff around to firstly clear out the area to be able to commence the construction. Then we will have to move the people back in again.
>
> ... It is just a phenomenon that would impact 1999 and 2000, because that is the period of time that we would actually be completing the project itself.

The Board considers that since the increase in Corporate Office Expenses is caused by the Calgary Master Plan, the expenses ought to be included in the capital cost of the project. With the costs included in capital, the principle of intergenerational equity is maintained and current customers are not charged for costs incurred by the project before the asset is used or required to be used.

Therefore, the Board directs TransAlta, in its refiling, to transfer the amounts of $1.5 million in 1999 and $1.4 million in 2000 in Corporate Office Expense to the forecast CWIP costs of the Calgary Master Plan for the respective years until such time as the asset is transferred from CWIP to rate base.

---

[270] Tr. p.2641
[271] Tr. p.2637-2638

(3) Sale of High River Service Centre

In its Application, TransAlta included the disposition of the High River Service Centre. TransAlta forecast a capital loss of $11.3 million in June 2000, the anticipated date of sale.

Position of TransAlta

TransAlta stated that the disposition of the High River Service Centre was due to internal restructuring and to improve cost efficiencies. The facility was anticipated to be sold in mid 2000 with a sale price of approximately $5 million. Net book value at June 2000 is estimated to be $16.3 million.[272]

TransAlta stated that the High River Service Centre, that began operation in 1992, was closed because internal restructuring and improvements in technology allowed TransAlta to manage its inventory from only one facility. TransAlta consolidated its operations in the Acheson facility that is more efficient for operations and more cost-effective.[273]

TransAlta explained that the decision to build the High River Service Centre in 1992 was prudent in the circumstances existing at the time, just as the current circumstances dictate that it is prudent and responsible to operate with only one such facility.[274] Internal restructuring and improved cost efficiency (including being able to better manage overall inventory levels through the introduction of the SAP System) have allowed TransAlta to manage its inventory from one location and reduce overall costs,[275] thus benefiting the customers.

TransAlta stated that the High River facility was built according to TransAlta's specifications. Representatives involved in the real estate industry have indicated that the facility will likely sell at less than book value, which may result in an $11 million dollar loss when compared to net book value.[276] However, TransAlta expected to save approximately $620,000 in annual inventory costs and $770,000 in annual operating costs.[277] These cost savings will be passed on to customers through the rates, therefore, TransAlta submitted that its closure of the High River Service Centre is appropriate.

TransAlta responded to ENMAX's objection to TransAlta's proposal to write off the anticipated loss on disposition of the High River Service Centre. TransAlta, was advised that, because of the special purpose of the building, it does not expect more than $5 million on its sale. TransAlta observed that this evidence was not contradicted at the hearing. TransAlta objected to

---

[272] Application Section 7
[273] Tr. p.1955-1956
[274] Tr. p.2777-2779
[275] Tr. p.1954
[276] Tr. p.1956-1957
[277] Tr. p.1958; CCA.TAU-55

ENMAX's argument that the loss should be written off at the time of sale and that it should be apportioned largely to land and borne by shareholders.

TransAlta submitted that to suggest that a relatively small parcel of land in southern Alberta, outside of any major urban area, would have a value approaching $19.8 million is contrary to common sense and should be ignored by the Board.

In response to the FIRM Customer's argument respecting TransAlta's proposed handling of the disposition of the High River Service Centre, TransAlta submitted that, after being properly included in rate base in 1992, it is not reasonable for the FIRM Customers to challenge the prudence of the decision in the current proceeding. By being included in rate base, the addition of the asset was deemed to be prudent at that time. TransAlta considered that circumstances have changed significantly. TransAlta stated it has made enormous strides in restructuring operations to reduce costs from what they would otherwise have been. TransAlta stated that FIRM Customers, while happy to enjoy the benefits, objected to paying the costs necessarily incidental to the restructuring activity. TransAlta submitted that the FIRM Customers cannot have it both ways. TransAlta considered that the closure of the High River Service Centre is a necessary feature of the restructuring, which, in total, is of significant benefit to the customers. TransAlta further considered it would be entirely unreasonable in these circumstances to require shareholders to absorb 50% of the loss that is expected to be incurred on disposition of the building.

Position of the Intervenors

ENMAX observed that TransAlta is forecasting a loss of $11.3 million on the anticipated sale of the High River Service Centre. The original purchase cost of the land and building was $19.8 million. Depending on the source, the net book value has been identified by TransAlta to be $16.3 million at the end of 2000 or at the end of 1998. ENMAX objected to TransAlta's proposal that customers absorb the forecast loss.

ENMAX considered that TransAlta has not provided evidentiary support for the fact that the transaction will occur as anticipated or that the value is appropriate. ENMAX stated that TransAlta's forecast, that the proceeds of disposition would be $5 million, was based on an unsubstantiated comment from one real estate advisor. The report, was not placed on the record by TransAlta, was not tested and cannot be relied upon by this Board.

ENMAX also considered that based on TransAlta's comment that it will get as much as it can, TransAlta has no incentive to maximize the value and, in fact, has an incentive to overstate the forecast loss where none is likely.

ENMAX was concerned that the transaction would take place during 1999 or 2000 since TransAlta stated that it is very difficult to find a potential buyer with the same requirements. TransAlta also stated that the sale might take two years or longer to complete. ENMAX submitted that the timing concern could be avoided by writing down the property at the time of

the actual disposition (versus a forecast of proceeds) when the value is known, the prudence of the transaction can be tested, and the timing is certain.

ENMAX also noted that there is no evidence of the apportionment of the value between the land and the building. In the absence of evidence it would be unreasonable to assume that the loss is attributable solely to the building without some portion of it being attributable to the land. ENMAX considered that it is reasonable to assume that the replacement cost or current cost of construction would not have decreased since 1992 such that a prospective buyer would not expect to pay less for the building than paid by TransAlta some six years ago.

ENMAX questioned TransAlta's claim that because the High River facility was customized for TransAlta, finding a potential buyer with the same requirements would be difficult. ENMAX stated that there is no evidence that TransAlta has explored the market or even obtained an appraisal that indicated the current or best use.

ENMAX stated one could reasonably question the prudence of the initial facility acquisition. TransAlta's reason for the change is the introduction of the SAP system and its ability to manage inventory levels better. The SAP system was tested extensively in the 1996 GTA as part of $24 million in software development costs sought by TransAlta. The Board accepted, in Decision U97065, TransAlta's promise of $5.6 million of savings.

ENMAX submitted that TransAlta's forecast disposition and the alleged loss are highly speculative, both in terms of actually occurring within the test period and amount. Customers should not be required to bear the burden of such a highly speculative loss. The property should be written off at the time of its eventual sale rather than allowing a forecast loss without adequate evidence in support. Further, without evidence of apportionment between land and building the loss should be apportioned primary to land. Consistent with past Board decisions, that loss should be borne by the shareholders.

The FIRM Customers summarized TransAlta's proposal to sell the High River Service Centre in 2000 as follows:

- Built and included in rate base in 1992.
- TransAlta owns the land and buildings.
- Material and inventory handling consolidated at the Acheson Service Centre.
- High River Service Centre used only for a small amount of emergency storage.
- Designed to handle the materials for the southern part of TransAlta's service territory for primary distribution and transmission and storage of other materials for corporate services.

The FIRM Customers calculated the forecast loss on disposal as follows:

Original Cost (Schedule 7.2.5, as revised in Exh.60)	$19.90 million
Accumulated Depreciation Dec. 31, 1998	$ 2.90 million
Net Book Value Dec. 31, 1998	$17.00 million
Proceeds of Disposal (Sch. 7.2.5, as revised in Exh.60)	$ 5.30 million
Net Loss	$11.70 million

Source: CCA.TAU-55, X60

The net loss on this transaction would be recorded through the accumulated depreciation account subsequent to the sale. Since the forecast sale is with respect to both land and building, the FIRM Customers could not see how the portion of the loss on land could be recorded through the accumulated depreciation account. The FIRM Customers submitted that TransAlta be directed, in its refiling, to provide a breakdown of the proceeds on sale, as well as a calculation of the net loss, for both land and buildings.

The FIRM Customers noted that by consolidating the High River facility with the Acheson Service Centre, TransAlta claimed that it had achieved annual cost reductions of $1,390,000.

The FIRM Customers addressed the issue of the prudence of TransAlta's initial decision, to construct a custom-built, state-of-the-art facility in High River. The High River facility was built and commenced operations only some 7 years ago in a non-test year and so there is no record available to review the prudence of management's decision to construct this state of the art centre. Typically such a building should have a service life of approximately 41 years. Given the lack of regulatory review at the time of construction, its addition to rate base has to be on the assumption TransAlta had done its due diligence and established that a custom-built facility was required. Now, only seven years later, TransAlta finds customers are better off with one service centre at Acheson. If this is true now, it must have been true seven years ago. The FIRM Customers stated that, while there may be merit in closing down the High River facility in 2000, the Board needs to deal with the issue of the forecast loss on disposition of the High River facility.

The FIRM Customers challenged TransAlta's argument that it had effected "additional efficiencies.... through the introduction of the SAP system and being able to manage overall inventory levels"[278] that allowed it to close down the High River facility. The FIRM Customers submitted there were inventory and other computer systems available to TransAlta, prior to the construction of this facility that should have provided TransAlta sufficient tools to determine whether the construction of a $20 million facility was warranted. Further, the FIRM Customers stated that the evidence is TransAlta's processes were either not efficient in 1992, or the decision

[278] Tr. p.1956

to construct the facility was done without much thought as to its need and as to why construction of another facility, in addition to the Acheson facility, was really necessary.

The conclusion reached by the FIRM Customers was that TransAlta's evidence suggests the existence of both the High River facility and the Acheson facilities resulted in increased costs to TransAlta's customers. The fact TransAlta expects to save $1.4 million annually by closing the centre down must, by implication, mean customers have in the prior years been paying a similar level of excess costs by having both facilities. If such excess costs have been incurred since 1993, it appears customers have paid excess costs in the amount of $9.1 million ($1.4 million x 7 years, 1993-99). In addition consumers have paid the revenue requirement costs of the rate base treatment of this facility over that time.

The FIRM Customers submitted it was poor planning and foresight on the part of TransAlta's management that resulted in the premature abandonment of this facility. TransAlta's management should bear some of the consequences of the High River facility decisions. Customers should not be held entirely responsible for the loss on the disposal of the High River facility. TransAlta management has to be held accountable to some degree for the major about face on such a significant investment.

The FIRM Customers stated that they are prepared to share the pain with TransAlta given the savings forecast to arise in the future from this decision and recommended the forecast $11.7 million loss be shared between customers and shareholders on an equal basis.

IPCAA submitted that TransAlta's request to recover the $11 million loss on the sale of the High River facility should be denied in this case. IPCAA stated that recovery of stranded costs should be subject to an auction to establish the true market value and any losses on these assets are mitigated by profits the utility can realize on other assets. TransAlta's approach of "losses to the customers: gain to the shareholders" should be rejected.

Board Findings

The Board considers that five issues arose in respect of the forecast loss on sale of the High River Service Centre as follows:

- TransAlta's forecast that the proceeds of disposition would be $5 million.
- The probability that the sale would not take place during the test years.
- Apportionment of the forecast transaction between land and buildings.
- Prudence of the initial warehouse acquisition.
- The allocation of the forecast loss to the functions.

The Board considers that ENMAX's concern that TransAlta based its determination of proceeds of disposition on the basis of a discussion with one real estate advisor to be valid. TransAlta also did not provide an appraisal or other evidence that it has explored the market or that the property

is listed for sale. TransAlta only stated that since the facility was designed to its specific needs, the property would be difficult to sell.

The Board also considers that ENMAX's concern that the sale might not take place during the test years, 1999-2000, to be valid. TransAlta's statement that the sale may take two years or longer to complete, gives credence to the concern. However, the Board is aware that there is a possibility that the sale could occur during the test period.

Historically the Board has considered gains or losses on disposition of property apportioned between land and buildings. The gain or loss on land was generally to the account of the shareholder and the gain or loss on the building to the account of the customers. A forecast of this apportionment is absent in this proceeding.

The Board notes ENMAX's position that it would be unreasonable to assume that the loss is solely attributable to the building and none to the land. The Board agrees with ENMAX.

The Board considers that the prudence or imprudence of the initial warehouse acquisition should have been addressed in the first proceeding when the facility was proposed to be included in rate base. The Board also considers that if the facts available today would have been available in 1992, TransAlta might have made a different choice. To consider the prudence issue in this proceeding would amount to retroactive rate making.

In respect of the allocation of the forecast loss, the Board notes the following transcript discussion:

> Q. ... this service centre would be used predominantly or has been used predominantly for distribution and/or transmission type functions. ...
>
> ...
>
> A. ... There would have been minimal amount of generation directly. High River is close to the hydro facilities that we have on the Bow River. It may be removed from the thermal plants, but it is certainly in close proximity to the hydro facilities.
>
> The High River service centre was also used to store a lot of materials and files for the corporate operation as well. So there are, or there were, generation file storage that took place there, generation's usage of any of our corporate materials.[279]

[279] Tr. p.1959-60

The Board considers that since there was only incidental use of the facility for generation purposes the loss should be allocated to transmission and distribution alone as follows:

High River Service Centre
Loss Allocation Factors

	Annual Allocation Factor*	Net Allocation Factor
Transmission	18%	29%
Distribution	44%	71%
Total	62%	100%

*These are the allocation factors used in the Allocation of Common Costs section of this Decision. The remaining 38% of costs are allocation to Generation

Further, the Board considers that the minimal use by the GENCO does not warrant trying to incorporate the actual sale results into the PPAs and/or Balancing Pool.

In summary, the Board finds as follows:

- TransAlta has not provided substantive evidence to persuade the Board that the forecast sale price of $5 million is reasonable;
- TransAlta has not provided definitive evidence that the sale will take place during 2000;
- an apportionment of the net proceeds of property sales to land and buildings is a requirement to appropriately determine the disposition of gains or losses; and
- that a fair allocation of the forecast loss to transmission and distribution is to use the ratio of the allocation factors for transmission and distribution as determined in the Allocation of Common Costs section of this Decision.

Considering the above circumstances and findings, the Board considers the following direction to TransAlta would be fair and reasonable for the purposes of arriving at a forecast for the test years. Accordingly, the Board directs TransAlta, in its refiling to:

- utilize a forecast sale price of $11 million (the average of TransAlta's proposed $5 million and the net book value of $17 million);
- apportion the forecast net loss of $6 million (i.e. $17 million minus $11 million) between land and buildings on the basis of the original cost of the land and the net book cost of the building;

- charge the portion of the $6 million net loss attributable to buildings to accumulated depreciation. By charging the net loss to accumulated depreciation the loss will be spread over the remaining life of the account; and
- use the High River Service Centre loss allocation factors to allocate the forecast loss to transmission and distribution.

The Board notes that it will deal with the disposition of the actual proceeds of the sale at the time of TransAlta's application for approval to sell and dispose of the High River Service Centre.

(4) Sustainable Development

TransAlta, in its Application, requested a $1.5 million Sustainable Development project for 1999. Although no specific investment had been identified, TransAlta considered that investment in greenhouse gas offset projects, where expenditures relate to construction/ownership of a revenue-producing asset, will bring benefits that will extend beyond the current fiscal period.[280]

Position of the Intervenors

The FIRM Customers stated that in addition to the $1.5 million of capital expenditures associated with "Sustainable Development" TransAlta also forecasted operating costs associated with these capital costs in the amount of $2.7 million in 1999 and $2.8 million in 2000.[281] These costs were $3 million during the period 1996-1998.[282]

The FIRM Customers considered that TransAlta's efforts in capturing greenhouse gases are commendable. However, while the proposed expenditures are to be made by the Utility company, evidence suggests the benefits would likely accrue only to the non-utility segment. With respect to the greenhouse gas offsets project, TransAlta confirmed it has affiliated, non-Utility operations outside Alberta producing CO_2 emissions.[283] The FIRM Customers stated that, if the regulated Utility develops a successful technology, there is no guarantee that affiliate companies will not utilize and benefit from such technology.

The FIRM Customers noted TransAlta's acknowledgement that it could realize revenues from some of the sustainable development projects,[284] but observed that these revenues are not reflected in the 1999/2000 forecast. The FIRM Customers also stated their concern that the accumulation of greenhouse-offset credits could be used for competitive purposes by both the Utility and non-utility segments.

---

[280] Application, section 5.2
[281] Tr. p.2004
[282] ENMAX.TAU-69(a) and Exhibit 103, Tr. p.2863
[283] Tr. p.2334
[284] Tr. p.2337

The FIRM Customers recommended one-half of the revenue requirement associated with the Sustainable Development projects should be considered as Utility related.

IPCAA submitted that the project is unnecessary at this time and should be rejected.

IPCAA, however, suggested that if the Board was to approve this project, TransAlta should be expressly obliged to ensure that all benefits (including any associated revenues), of whatever CO_2 offset or reduction projects it might in fact pursue, accrue to the regulated Utility.

Position of TransAlta

TransAlta submitted that the costs projected in relation to sustainable development are reasonable, particularly in light of the fact that TransAlta is one of the largest emitters of CO_2 in Canada. As such, TransAlta believes that it has a responsibility to attempt to alleviate some of its emissions.

TransAlta stated that it proposed to incur the costs associated with a number of sustainable development projects now under review. TransAlta submitted it is highly desirable that such offset projects proceed and that this will be of material benefit to its customers.

TransAlta responded to IPCAA's request that the Board direct TransAlta to accrue all associated benefits with any CO_2 offset reduction projects to the regulated utility. TransAlta committed to do so.[285] Given this, and the need for TransAlta to develop projects to offset its CO_2 production, TransAlta submitted that its costs are both just and reasonable.

Board Findings

At issue is whether or not the benefits to be derived from the Sustainable Development investment will accrue to the regulated utility operations or the non-regulated utility operations of TransAlta. The FIRM Customers suggested that only one-half of the expenditure should be considered utility cost, whereas IPCAA suggested rejection of the expenditure for utility purposes. IPCAA offered that if the Board approved the expenditure, then TransAlta should be obliged to credit the regulated utility with the future benefits from this expenditure.

The Board notes from TransAlta's response to ENMAX.TAU-69(a and e) that, in addition to the requested $1.5 million capital expenditure, there are operating costs for Sustainable Development in the Application. Sustainable Development is defined as the administration of environment related issues that can relate to all business units. Forecast operating costs for Sustainable Development are $2.7 million in 1999 and $2.8 million in 2000.

TransAlta further explained that Sustainable Development "In addition to being concerned with CO_2 offsets, that group is also very much involved with environmental issues, and that is issues

[285] Tr. p.2336

of all types, whether it be associated with generating facilities, whether it be PCBs, things of that nature."[286]

TransAlta stated in its response to FIRM.TAU-67(a) that projects for the Sustainable Development capital expenditure could include collection and utilization of landfill methane gas to generate electricity and capturing/gathering/processing and marketing coal bed methane gas from mines of large coal companies, both active and settled panels, where gas is currently vented. These projects are in the concept stage and have not been specifically identified and are to be amortized over 40 years, which is the same time period as that used for thermal plant equipment.

The Board notes that the Sustainable Development projects contemplated are generation related projects. New on site generation would be required to utilize the methane gas that is recovered and this new generation would not be regulated generation.

The Board agrees with the FIRM Customers that TransAlta's efforts in capturing greenhouse gases are commendable. Reduction of greenhouse gases escaping into the atmosphere will benefit society as a whole. The Board however considers that its responsibility is to ensure that customers of the regulated utility are paying for capital additions that are to their benefit. In addition, the Board has a responsibility that costs properly the responsibility of non-regulated entities are paid by that entity to assist in development of a level playing field between competitors. As the benefits of the Sustainable Development Project will be recognized at some time in the future, there is no way of ensuring that the customers of the regulated TransAlta GENCO utility will receive the benefit. It would be difficult to track credits from such expenditures at uncertain times in the future when the GENCO is no longer regulated by the Board. The Board considers that the more likely scenario is that the benefits of the Sustainable Development projects will be received by non-regulated generation affiliates of TransAlta.

Therefore, the Board directs TransAlta, in its refiling, to remove the $1.5 million capital costs for the Sustainable Development Project from rate base. Also, the Board directs TransAlta, in its refiling, to remove any related operating costs from the $2.7 million in 1999 and $2.8 million in 2000, forecast operating costs that are included in TransAlta's Corporate O&M costs for Sustainable Development. The Board will accept TransAlta's remaining Sustainable Development forecast operating costs for operational requirements, such as PCB handling and disposal, and other ongoing environmental initiatives.

(5) SD Projects

In its Application TransAlta included $3.7 million in 1999 and $2.5 million in 2000 of operating costs for SD Projects. TransAlta attributed these costs to CO_2 offset projects.

[286] Tr. p.2004

Position of TransAlta

SD projects were defined by TransAlta to include CO_2 projects allocated to generation. TransAlta explained that the activities included in SD Projects are:

> The SD Projects are the CO_2 offset projects that TransAlta is engaged in and is considering additional ones to be engaged in, and it is the operating component of those particular projects.[287]

TransAlta also stated that SD Projects are classified "as being research and development because of the tax treatment that those type of expenditures will receive."[288]

Position of Intervenors

Intervenors did not specifically address the O & M costs for SD Projects.

Board Findings

The Board considers at issue whether the O & M costs for SD Projects are for the regulated or unregulated activities of TransAlta. The Board acknowledges that CO_2 reduction efforts will benefit society. The Board, however, also considers that its responsibility is to ensure that customers of the regulated utility are paying for costs that are to their benefit.

The Board notes the discussion, at Tr. p.2334-2335, that TransAlta's unregulated operation outside of Alberta is receiving revenues from co-generation sales to Ontario Hydro. The Board considers that the contracts with Ontario Hydro result from, in part, the efforts of the SD Projects group. TransAlta, however, has not offset any revenues to its regulated operation that resulted from the R&D expenditures provided by regulated customers.

The Board considers that TransAlta's GENCO will achieve CO_2 reductions in the ordinary course of business as generating units or plants are retired. For example, when Wabamun units 1 to 4 are retired, TransAlta will achieve an 18 percent reduction in CO_2 emissions for its regulated units. Furthermore, when Sundance 1 - 2 are retired in 2010, TransAlta will have achieved a 35% reduction from 1990 levels. The Board is required to utilize the scheduled retirements listed below as the basis for its decisions in the 1999 – 2000 time period. The following table illustrates the possible reductions if, in fact, the retirements take place as forecast:

[287] Tr. p.2004
[288] Tr. p.2004

TransAlta CO_2 Reductions from 1990 Levels				
Units	MCR[1](MW)	Retirement Date[2]	Stack Emmission Reduction on Retirement[3]	Cumulative Reduction (%)
Wabamun 1-4	548	2003	4.7	18%
Sundance 1-2	560	2010	4.3	35%
Sundance 3-4	710	2016	5.5	56%
Sundance 5-6	721	2018	5.5	77%
Keephills 1-2	766	2023	5.9	100%
Total			25.9	100%

Notes: [1]Decision U97065, p.705
[2]Decision U97065, p.712
[3]1990 Emissions in millions of tonnes of CO_2 per year

Source: Exhibit 129, Tr. p.3697

The Board considers that with the scheduled retirement of regulated generation, TransAlta will meet or exceed CO_2 reductions that may be required by the Kyoto accord.

With respect to ongoing SD O&M, the Board considers that these projects were undertaken for the benefit of regulated generation and certain ongoing SD expenses are required to meet societal and operating requirements for current regulated utility operations. The Board further considers that regulated customers are entitled to receive some payback for the R&D expenditures provided by them that is now producing revenues for TransAlta's unregulated affiliate. Accordingly, since the efforts of the regulated operation of TransAlta has contributed to the revenues received by the unregulated affiliate, the Board considers that it is appropriate for TransAlta to share the SD Projects O&M costs with the unregulated operations. Therefore the Board directs TransAlta, in its refiling, to reduce the SD Projects O&M forecast amounts of $3.7 million in 1999 and $2.5 million in 2000 by 50% to $1.85 million in 1999 and $1.25 million in 2000.

(6) Automated Mapping/Facilities Management

Position of the REAs

The REAs were concerned with the conditions under which TransAlta provided land based mapping services to "C" Contract REAs. The REAs considered there were two problems with TransAlta's position and quoted TransAlta's response as follows:

> TransAlta provides a copy of single line and system maps to REAs at the time they go on option "C". There is no cost for this service. In addition, TransAlta offers to provide digital maps on a one-time basis at cost. TransAlta also offers to provide a map of adjacent TransAlta facilities on an annual basis. This is done on the basis that the REA will provide REA mapping information to TransAlta. No additional mapping services are offered to "C" Contract REAs.[289]

The REAs stated that the first problem is that TransAlta offers to provide digital maps on a one-time basis at cost. TransAlta advised that the automated mapping and facilities management project was completed in 1997. The REAs considered that since the costs of developing the mapping program are recovered in the demand portion of the rates which REA members pay, there should be no cost to the REAs for TransAlta to provide a computer copy of their service area to the REAs on request.

The second problem is that TransAlta provides a map on an annual basis to the REA on condition that the REA will provide REA mapping information to TransAlta. The REAs stated that TransAlta expects electronic information from the REA and in return will provide a paper map. The REAs stated that TransAlta benefits from REA supplied information to keep the picture of the electrical system in the service area complete.

The REAs requested that the Board direct TransAlta to provide digital mapping information on a regular basis to those REAs who request it on the clear understanding that the REA will in turn provide information of its system enhancements and changes on the same basis. The REAs offered that each party would bear its own costs and each party's information would benefit the other.

Position of TransAlta

TransAlta did not address the concerns of the REAs.

Board Findings

The Board notes that the REA systems interconnect with the TransAlta system. Changes in one system could affect the other system. The information exchange is important to both parties. The Board is also aware that in order to exchange digital information the software used must be compatible to get the desired results.

The Board notes the offer of the REAs for each party to bear its own costs to facilitate the information exchange between the REAs and TransAlta. The REAs' request for digital information in this age of electronic data is a reasonable one.

[289] Exhibit 97, Tr. p.2733

Therefore, the Board directs TransAlta and the REAs to resolve any software compatibility issues and establish methods and procedures to exchange digital mapping information. The Board directs TransAlta, in exchange for REA system information, to supply the REAs with digital mapping information at no charge to the REAs, commencing immediately upon release of this Decision.

(c) Corporate Operating Expense

(1) Labor and Materials Escalation

Position of the FIRM Customers

The FIRM Customers provided common argument and recommendations respecting GENCO/TRANSCO and DISCO Labour and Materials escalation. That argument is set out in the GENCO section of this Decision. The FIRM Customers stated that their argument and recommendations respecting TransAlta GENCO were equally applicable to TransAlta Corporate Services.

Position of TransAlta

TransAlta's position respecting Labour and Materials escalation is included in the GENCO section of this Decision.

Board Findings

The Board has dealt with labour and escalation rates in the Part 4–TAU, Section 2(b)(2)(D) of this Decision. For the same reasons as set out in that section, the Board approves TransAlta Corporate Services forecast labour and escalation rates. The Board notes that the TransAlta Pension Reserve Section of this Decision directs a reduction to pension expense which will in turn reduce the operating labour component of Corporate Services cash operating expenses.

(2) Telecommunication Expense

Telecom expenses are included as part of TransAlta's Information Services costs in the Corporate Services budget. The costs are allocated to business units based on actual usage.

Position of the Intervenors

The FIRM Customers noted that, in 1999, TransAlta forecasts a telecom expense of $9.4 million.[290] Applying a general escalation factor of 1.6%, the 2000 budget would appear to be approximately $9.6 million.[291] However, in response to an undertaking, TransAlta acknowledged

[290] FIRM.TAU-60
[291] Tr. p.3656

the 1999 forecast is overstated by $800,000 and should be reduced to $8.6 million.[292] A similar reduction of $800,000 is also indicated for the 2000 forecast, reducing the estimate to $8.7 million.[293]

Even with these adjustments, the FIRM Customers considered that the Telecom budget still appears overstated. For the first 9 months of 1998 the telephone component of Telecommunications costs was $3.5 million, or approximately $1.2 million per quarter.[294] Using $1.2 million/quarter, the total telephone charges should have been around $4.7 million for 1998. When compared to TransAlta's 1998 forecast of $5.8 million, it indicates a difference of approximately $1.1 million.[295]

To explain this difference, TransAlta indicated its estimate for the final quarter in 1998 is $2.3 million due to the ramp-up of telephone charges associated with the new Call Centre.[296] However, FIRM.TAU-38, stated that the Call Centre cost $0.4 million for all of 1998. Even if one assumes all this cost incremental to telephone charges in the 4th quarter, it still leaves $0.7 million of the $1.1 million difference, unexplained.

To arrive at their 1999 forecast of $6.7 million, TransAlta increased the $5.8 million 1998 forecast by 16%.[297] However, this level of increase is excessive, particularly since TransAlta indicates a factor of 1.6% is appropriate for 1999 and 2000.[298] Further, Call Centre telecommunications costs are $0.6 million, or $0.2 million above the 1998 Current Estimate.[299] Even if one assumes all the Call Centre costs are incremental, the FIRM Customers estimate for telephone charges would still be only $5.4 million, $1.3 million below TransAlta's projection.[300] This difference is illustrated in the table below.

[292] Exhibit 106; Tr. p.3041; FIRM.TAU-60; TransAlta Evidence, Section 5.3
[293] Tr. p.3656
[294] Exhibit 103 at Tr. p.2585, p.3657
[295] Exhibit106, Tr. p.3041
[296] Tr. p.3657
[297] Exhibit 106, Tr. p.3041
[298] Tr. p.3656
[299] FIRM.TAU-38
[300] Exhibit 106

Telephone and Toll Charges
($ millions)

		TransAlta	FIRM	Variance
1998	Jan-Sep	3.5	3.5	
	Oct-Dec	2.3	1.2	
	Jan-Dec	5.8	4.7	1.1
	Adjust		0.4	
	Total	**5.8**	**5.1**	**0.7**
1999	Increase at 16%	0.9		
	Increase at 1.6%		0.1	
	Call Centre		0.2	
	Total	**6.7**	**5.4**	**1.3**

Based on the foregoing, the FIRM Customers submitted the telecommunications estimate for 1999 should be reduced by the $0.8 million indicated by TransAlta and by an additional $1.3 million as discussed above. The total reduction for 1999 would then be $2.1 million. Likewise, for 2000, the FIRM Customers recommended a similar reduction be made.

Position of TransAlta

In its Application TransAlta stated that approximately $1.7 million of the $2.8 million increase in Office Expenses between the 1996 refiling and 2000 forecast is related to telecommunications. The Call Center became fully operational 30 June 1998 and Telecommunications forecasts for 1999 forecast and 2000 forecast reflect operation costs and expected increasing volumes of the Call Center and dispatch.[301]

TransAlta noted the FIRM Customers' submission that the telecommunications expense is overstated by a total of $2.1 million in each of 1999 and 2000. The rationale used for this is the original telecommunications amounts per FIRM.TAU-60, Exhibit 106 - T3041, and FIRM.TAU-38.

TransAlta acknowledged that telecommunications expense was overstated by $0.8 million in 1999.[302]

With respect to the references to FIRM.TAU-38, TransAlta noted that this Information Response was for the Call Centre only and did not reflect incremental inbound costs. Accordingly, TransAlta submitted that the IS costs in total are reasonable, especially when considered with the overall downward trend in Corporate Services costs as per Exhibit 89.[303]

[301] Application 5.1.0.3.3
[302] Exhibit 106
[303] TransAlta Reply, p.66-67

Board Findings

The Board notes that the FIRM Customers used the first nine months of 1998 to estimate full year 1998 actual telephone expenses of $5.1 million as a basis for comparison to the 1999 forecast telephone expense of $6.7 million.. TransAlta explained that telephone expense for the last quarter of 1998 would be $2.3 million as the full effect of the new Call Centre was not included in the first nine months. The Board also notes the FIRM Customers' argument that the incremental cost of the Call Centre does not warrant the increase of 16% over 1998 in the 1999 forecast of telephone expense.

The Board is not convinced that using a nine-month average is indicative of the rest of the year. The Board considers that other events, such as the Call Centre, and their effect must also be taken into account in a forecast. The Board is also not convinced that a one time 16% increase in a particular expense category is unreasonable given the full operation of the Call Centre in 1999, the extra cost of incoming calls and the reduction in other related expense categories.

Therefore, the Board directs TransAlta, in its refiling, to reduce the 1999 total telecommunications forecast of $9.4 million by $0.8 million as acknowledged by TransAlta for a revised 1999 forecast of $8.6 million. Further the Board directs TransAlta, in its refiling, to calculate its 2000 forecast by adding 1.6% to the $8.6 million determined by the Board for 1999.

(d) Allocation of Common Costs

Common costs are the costs that a corporation incurs by having one function do a common job for all other functional groups in the corporation. Examples of common costs are Accounting, Marketing and Head Office costs. The allocation of common cost to each function are generally accomplished by using certain factors that fairly represent the level of work done for a functional group. Direct assignment, number of employees or number of transactions and other factors are used to allocate costs that fairly represent the services provided to the functions. A combination of several factors is also used. Residual amounts that cannot be allocated with specific factors can be allocated using a general factor such as property or all operating expenses.

The purpose of allocating common costs to functions is to assign the costs to the functions that caused the costs to be incurred. In this manner the function that was responsible for the costs recovers those costs through its revenue requirement.

Decision U97065, Board Direction G-7, directed TransAlta to "...to undertake detailed studies of their functional and cost allocation methodologies and incorporate the results of such studies in their next GRA."

Position of the Intervenors

ENMAX noted that TransAlta did not file a detailed study and rationale, as directed by Board Direction G-7, as did EPGI/EPTI and AE. ENMAX also noted that in response to FIRM.TAU-80 TransAlta indicated that corporate service gross plant is allocated to business units based primarily on the historical practice of gross year-end property. During cross-examination, the fact that there was no study conducted or filed with respect to TransAlta's property allocation was disclosed.[304]

ENMAX submitted that the Board directions must be complied with, otherwise, the regulatory process becomes obstructed, frustrated and delayed.

With respect to Corporate Service buildings, ENMAX considered that the selected allocation method was entirely without merit. After directly assigning $9.3 million to business units, the residual $83.8 million was allocated one-third to each of the three business units.[305] In Exhibit 124 TransAlta added another $28.7 million of buildings for a total residual of $112.5 million to be allocated using the one-third allocation method. The simple one-third allocation was used without regard to any analysis of the property within that class.[306] ENMAX considered this resulted in a misallocation of costs among business units.

ENMAX submitted that the bulk of the costs have little relation to generation and are primarily distribution related. ENMAX further submitted that only the Head Office ($72.3 million) should be allocated to generation for a maximum allocation of $24.1 million ($72.3 ÷ 3).

Position of TransAlta

In its Application TransAlta stated that, in accordance with Board Direction G-7, it undertook a detailed study of the allocation of Corporate Services costs to the business lines. As a result of this study, the portion of Corporate Services costs allocated to Generation has been reduced and the portion of Corporate Services costs allocated to Distribution has been increased.[307]

TransAlta also stated that a more extensive analysis of Corporate Services was done. In order to take advantage of economies of scale, a number of Corporate Services departments incur costs that are then allocated or assigned. Primary drivers used include:

- direct assignment based on professional judgment,
- allocation based on percentage of employees,
- allocation based on mid year gross property,
- allocation based on revenue requirement

[304] Tr. p.1922-1923, 3467-3468
[305] Tr. p.3474
[306] Tr. p.3471
[307] Application Tab 5.1

- allocation based actual usage,
- allocation based on desktops and
- allocation based on a combination of the above.[308]

During cross-examination TransAlta explained that $7.5 million of the total Corporate Services costs were charged to the non-regulated activity and not included in the Application.[309] TransAlta considered the amount of Corporate Services costs included in the Application, which is net of the amount allocated to the non-regulated activity, to be appropriate.[310]

In response to ENMAX, TransAlta submitted that it had fully complied with Board Direction G-7 with respect to operating expense. The discussion in the 1996 hearing that led to the Board Direction related specifically to operating expense. Therefore, TransAlta focused on the allocation methodologies for operating expense. TransAlta noted that no Intervenor took exception to TransAlta's allocation of Corporate Services operating expense in argument.

TransAlta submitted that it had complied with Board Direction G-7 with respect to operating expense as that was the primary focus of the direction.

In respect of property allocations TransAlta acknowledged that, in the Application, property was allocated based on historical methods using mid-year gross property.[311] After the information response process, TransAlta determined that the use of mid-year gross property allocation would not be sufficient and prepared revisions to property. TransAlta further acknowledged that the allocation was refined in the preparation of revised depreciation schedules.[312] TransAlta considered that while this allocation is not perfect, it is considerably better than using historical mid-year gross property balances.[313]

TransAlta viewed the allocation of property as an evolutionary process that is expected to be fine-tuned and improved over time.[314] TransAlta considered that the 1/3 allocation for Corporate Services property is better than using mid-year gross property. With respect to the ENMAX submission that only the Head Office need be allocated to Generation, TransAlta stated that the High River Service Centre does service hydro and the Acheson Service Centre services the thermal plants.[315] The remaining corporate building balances are minimal.

---

[308] Application Tab 5.3
[309] Tr. p.2964
[310] TransAlta Argument, p.37
[311] FIRM.TAU-80
[312] Tr. p.3467, Exhibit 60, Exhibit 81
[313] Tr. p.1922, p.3472
[314] Tr. p.1922-1943
[315] Tr. p.1960, p.3707

TransAlta submitted that the method for allocation of property as revised in Exhibit 60 and shown in Exhibit 81 is fair.[316]

Board Findings

The Board considers that ENMAX has raised two issues in respect of cost functionalization and the allocators used to charge common costs to the functions. The first issue is whether or not TransAlta has complied with Board Direction G-7, and the second issue is the appropriateness of using a one-third allocation of Corporate Services buildings to business units.

The Board notes that TransAlta, at Tab 5.3 of its Application, provided the methodologies used to functionalize and allocate Corporate Services costs to the Genco, Transco and Disco business units. TransAlta also stated that it "...has done a more extensive analysis of Corporate Services costs." The result of the analysis was that fewer costs were allocated to generation and more costs allocated to distribution. The difference between this filing and the 1996 GTA are as follows:

TransAlta Allocation of Corporate Service Costs (as filed)			
	Generation	**Transmission**	**Distribution**
1999/2000 GTA	38%	18%	44%
1996 GTA	54%	22%	24%

In reply TransAlta further stated that "In the 1996 hearing, the discussion which led to the Board Direction related specifically to operating expense."

The Board also notes that TransAlta refined the allocation of property to achieve a better allocation of costs to business units. The Board considers this refinement as a step in the right direction. However, the Board considers that the one-third allocation of Corporate Services buildings to business units to be arbitrary and does not fairly represent costs caused by the respective business units.

The Board is not convinced that TransAlta has complied fully with the spirit and intent of Board Direction G-7. The Board Findings in Decision U97065 (p.80) noted that "An accurate functionalization of costs is important, especially under the new industry structure." And cited an example using "...existing generating plant costs..." to point out the consequence if these costs are inappropriately functionalized. The Board was also of the view that "It is therefore essential that costs be functionalized appropriately and consistently among utilities." The Board also recognized "that it will be necessary to develop methods to allocate common costs that cannot be readily functionalized." The spirit and intent is to accurately functionalize and allocate common costs to the functions regardless of whether the cost is an operating expense or a capital cost.

[316] TransAlta Reply, p.72-73

The Board is also not convinced that a "more extensive review" constitutes the detailed study directed in Decision U97065. The Board notes that EPGI/EPTI and AE did file a detailed study to comply with Board Direction G-7. The Board considers that the time scheduled between the Board Decision and filing date for the refiling will be too short for TransAlta to provide a detailed study. Therefore, the Board will, with reluctance, accept as filed, TransAlta's allocation of Corporate Services operating costs and the allocation of Corporate Services property. The Board accepts, as proper, TransAlta's direct assignment of $9.3 million of Corporate Services buildings to business units. With respect to the allocation of residual Corporate Services buildings, the Board considers the allocation percentages for Corporate Services operating costs to be a better measure of business unit activity and required building plant assets than the arbitrary one-third allocation method. Accordingly, the Board directs TransAlta, in its refiling, to allocate the $112.5 million residual Corporate Services buildings on the same basis as Corporate Services operating costs with the exception of the High River Service Centre which shall be allocated 29% Transmission and 71% Distribution in accordance with the Board's findings earlier in this Decision.

The Board directs TransAlta to comply with Board Direction G-7 and file the detailed study in its next GTA for both Corporate Services operating cost and Corporate Services property. The study is to include justifications that the methods chosen fairly functionalize and allocate costs to business units (including unregulated business units).

(e) Incentive Compensation

Position of the FIRM Customers

The FIRM Customers noted that both EP and TransAlta had incentive compensation systems for their employees. These systems would allow employees to obtain additional compensation based upon achieving or exceeding specified performance objectives.

The FIRM Customers had several concerns with these systems. In discussing the EP system the following concerns were noted (details of the FIRM Customers argument on this issue are provided in Part 3 – EPGI/EPTI, Section (l)(c), Compensation Program of this Decision):

- A large number of employees were expected to receive incentive compensation above "normal" performance standards.
- There was a built-in "incentive" to err on the conservative side when preparing forecasts as the people preparing forecasts would have a personal stake in the profit of the company.

The FIRM Customers noted the same concerns with regards to TransAlta's incentive compensation programs. They urged the Board to give careful consideration to the possible

impact these incentive schemes may have on forecasting, particularly where historical data suggested a pattern of over-forecasting.[317]

Position of TransAlta

In response to the concerns of the FIRM Customers TransAlta noted that a review of the response to the referenced information response ENMAX.TAU-34(i) (iii) indicated that no incentive compensation amounts were included in the filing for out-of-scope staff (non-union staff). This was expanded in TransAlta's letter to the Board dated 13 April 1999[318] which removed from the filing the incentive compensation amounts for in-scope employees.

Part (iv) of the response to ENMAX.TAU-34(i) stated that:

> ...when employees adopt practices/procedures which result in TransAlta exceeding expected performance (and therefore incentive compensation payouts are made), TransAlta shareholders gain in that particular year to the extent net income to the Corporation is higher. The incentive compensation program was designed to be self-funding, which means that the incentive program is funded from the amount by which the expected performance is exceeded.

Part (v) of the response stated

> when employees adopt practices/procedures which result in TransAlta exceeding expected performance (and therefore incentive pay-outs are made), TransAlta's customers gain. This is because in all future regulatory proceedings, a new benchmark is set for expected performance.

TransAlta submitted that customers have continuously benefited from TransAlta striving to achieve productivity improvements. Furthermore, TransAlta submitted that there was no evidence to support the FIRM Customers suggestion that budgets are padded so that an incentive compensation payout is made. As stated in the response in part (v) above, a payout is only to be made when actual performance exceeds expected performance. Expected performance is to be measured against continued improvement from prior years and not an inflated budget. Further, Mr. Janke stated:

> ...in the incentives that we have for employees, there are incentives that are geared towards superior performance when it comes to customer service, superior performance in regards to safety, and those are benefits that are being realized by the customers as they happen. There may not be a specific dollar amount that you can attach to that, but certainly the customers see the benefit of that.[319]

[317] FIRM Customers Argument, p.69
[318] Exhibit 59
[319] Tr. p.2023

TransAlta submitted that incentive compensation programs have been and will continue to be integral components in achieving productivity improvements which ultimately result in lower costs to customers.[320]

Board Findings

The Board adopts the view that the utility management has the responsibility for designing and implementing an employee compensation program consistent with the market conditions in which the utility operates, subject to regulatory oversight. The Board notes the cost of TransAlta's incentive compensation is to be funded by any achieved savings or by shareholders. The Board accepts TransAlta's Incentive Compensation Program as a reasonable program for obtaining and maintaining prospective and current employees.

The Board expects TransAlta to ensure that proper checks and balances are in place within the budget process to limit the possibility of bias being introduced with respect to TransAlta's forecasts. Further, the Board, with the benefit of intervenor testing, has the ability and responsibility to ensure that forecasts approved for the test years are reasonable.

The Board directs TransAlta, in its refiling, to remove the incentive compensation amounts for in-scope employees as indicated in TransAlta's letter of 13 April 1999.

(f) Income Tax

Various methods have been used in the past to determine the income tax component of the revenue requirement for regulatory rate-making purposes. Recently, the Canadian Institute of Chartered Accountants (CICA) set out, in its Handbook section 3465, a revised method to be used to recognize, measure, present and disclose income taxes in an enterprise's financial statements for fiscal years beginning on or after 1 January 2000. The CICA also encouraged earlier adoption of this method, which, for purposes of this Decision, is referred to herein as the "liability method."

(1) Income Tax Methods

The following are descriptions of the various methods.

Flow-Through

The utility pays the least amount of income taxes for a period by claiming all available deductions to which it is entitled under existing legislation to compute taxable income. Financial

[320] TransAlta Reply Argument, p.75

statement income prepared from the utility's accounting records will differ from taxable income because of:

(i) amounts recorded in revenue and expense that are neither subject to income tax nor allowed as deductions for income tax purposes (referred to as permanent differences) and

(ii) amounts recorded in revenue and expense for accounting purposes in a period that does not coincide with the taxation year in which they are included in the computation of taxable income (referred to as timing differences).

Only income taxes actually payable on taxable income are included in the utility's revenue requirement and recovered through customer rates.

Normalized Deferred Tax (NDT)

Timing differences are relevant in the determination of the income taxes that are included in the utility's revenue requirement and recovered through customer rates. The income tax charge has two components. Using the flow-through method, the utility records a charge for the least amount of income taxes actually payable by claiming all deductions to which it is entitled in computing taxable income. In addition, on the basis that income tax expense in a period should be determined on accounting income for a proper matching of revenues and expenses, the utility also records a charge for deferred income taxes.

The amount of deferred income taxes recorded is calculated on the timing differences created between accounting income and taxable income, using statutory income tax rates in effect at the end of the year. Accumulated deferred income taxes are not adjusted subsequently for changes in income tax rates. The accumulated deferred tax balance is reflected in the utility's capital structure as no-cost capital.

Normalized All Taxes Paid (NATP)

The utility adjusts permissive income tax deductions, which are timing differences, to equate taxable income with accounting income adjusted for permanent differences. By making taxable income equal to accounting income, the amount used for calculating deferred income taxes is zero, hence the name normalized all taxes paid. The income taxes charged for the period are the same as the aggregate amounts computed under the NDT method. However, all income taxes that are included in the revenue requirement and recovered from customers are actually paid to governments in respect of the period.

Liability (Future Income Tax)

The income tax charge has two components. Using the flow-through method, the utility records a charge for the least amount of income taxes actually payable by claiming all deductions to which it is entitled in computing taxable income. Secondly, the utility records an amount for future

income taxes that is calculated in respect of the differences between the carrying amounts of its assets and liabilities and the related income tax basis of those assets and liabilities.

The differences between the carrying amount and the tax basis of assets and liabilities are referred to as temporary differences, which may be either:

(i) Deductible temporary differences, that will result in deductible amounts in determining taxable income of future periods when the carrying amount of the asset or liability is recovered or settled; or

(ii) Taxable temporary differences, that will result in taxable amounts in determining taxable income of future periods when the carrying amount of the asset or liability is recovered or settled.

Future income taxes are measured each year using the income tax rates and the income tax laws that are expected to apply when an asset is realized or a liability is settled. Unlike deferred income taxes, future income tax balances are valued each year based on current rates of income tax. Amounts that result in income tax benefits (tax reductions) are referred to as future income tax assets and amounts that result in income tax expense are referred to as future income tax liabilities. The future income tax balance is included in the utility's capital structure as no cost capital.

(2) Currently Approved Method

TransAlta was directed, in Decision U97065, to compute federal income taxes for 1996 and subsequent years using the NDT method and to continue to compute provincial income taxes using the flow-through method. Previously TransAlta used the NATP method for federal income taxes. In calculating federal income taxes for regulatory rate-making purposes, TransAlta was further directed to maximize all deductions in the manner as permitted under the provisions of the Income Tax.

In years when the income tax component of its revenue requirement was calculated using the flow-through method, TransAlta was not required under generally accepted accounting principles to record deferred income taxes in its accounts. It was, however, required to calculate and disclose the amounts it did not record in the notes to its financial statements. The notational balance has been referred to as unrecorded, or unbooked, deferred income taxes. In other years when TransAlta used the NDT method, it recorded, or booked, deferred income taxes in its accounts. As a consequence of using the different methods to account for income taxes, TransAlta was also directed, in Decision U97065, to provide the manner by which it would propose to deal with both unbooked and booked deferred income tax balances, including, more specifically, a plan for the disposition of the booked balance that represented money already collected from customers. In addition, TransAlta was directed to provide a minimum five-year

forecast of federal income taxes calculated using the NDT method and of provincial taxes calculated using the flow-through method.

(3) TransAlta's Proposed Method

TransAlta stated that it reached crossover for federal income tax purposes in 1998, which is the point where its net deductions used to calculate taxable income become less than the related expenses used for determining accounting income. Also at this time, accumulated booked deferred income taxes begin to be drawn down, normally causing a reduction in the income tax charge. Unless TransAlta makes significant capital additions in the future, its income for income tax purposes will continue to exceed its accounting income for the same periods.

In previous years TransAlta, because it was a regulated utility, was not required under generally accepted accounting principles to record deferred income taxes in its accounts when its approved rates included only current taxes payable as a cost component of the revenue requirement. However, it was required to maintain a separate record of unbooked deferred income taxes, which it reported in the notes to its financial statements. In applying deferred tax drawdowns it proposed to offset these unbooked amounts before reducing recorded amounts. Under this proposal TransAlta effectively is using the flow-through method to calculate federal income taxes because only the income taxes actually payable, based on taxable income, would get included in the revenue requirement until all unbooked deferred income taxes have been eliminated.

TransAlta has not changed its method of recording taxes for provincial purposes and continues to record these taxes using the flow-through method.

During the proceeding, the Board requested that TransAlta provide a schedule[321] illustrating the effects of drawing down 50% booked and 50% unbooked deferred income tax in each of the test years.

Position of TransAlta

TransAlta's position was summarized as follows:

> We are now moving into certainly a constantly-changing, ever-changing regulatory environment, and we feel that the customer that we have today may well be quite different than the customers we have tomorrow, and we have this fairly significant amount of unrecorded deferred income taxes in the neighbourhood of $60 million that needs to be addressed prior to... drawing down

[321] Exhibit 193

what has already been booked in the books and what is collected from the customers already.[322]

As a result of a Negotiated Settlement with customers TransAlta used the flow-through method to calculate federal income taxes in 1998 and applied a draw down of $9.8 million against unbooked deferred taxes. TransAlta proposed that the draw down of the remaining large, unbooked tax balance continue in 1999 and 2000 in order to avoid unnecessarily burdening the remaining customers in the future. TransAlta also argued that, with the advent of deregulation and customer choice, the unrecorded deferred taxes should be recovered first to reduce the risk of non-recovery in the future.

TransAlta stated that the proposal of drawing down a combination of booked and unbooked deferred income taxes reduces federal income taxes included in rates for the test years. However, TransAlta noted that the rate of recovery of unbooked deferred income tax would be reduced by 50%, thus increasing the overall risk of recovery to TransAlta.[323]

TransAlta stated that its proposal ensures that the customers of today (who may be different from those of tomorrow) bear responsibility for the federal unrecorded liability of approximately $50 million. To do otherwise may result in customers with no choice being left to bear this cost.

TransAlta noted that the liability method, proposed by ENMAX, would attract additional Large Corporations Tax.

TransAlta stated that ongoing removal and replacement of equipment is considered to be capital in nature, since a new asset is created. For this reason, costs of removal, net of any salvage proceeds, have historically been added to income tax depreciation pools, referred to as undepreciated capital cost (UCC). The resulting annual claim from UCC becomes a timing difference. TransAlta further stated that historically it has not forecast any increase to rate base due to costs of removal and accordingly does not forecast any increase to UCC due to costs of removal. TransAlta contended that had it forecast costs of removal, the additional increase in return, tax and depreciation would be well in excess of the tax shield. TransAlta submitted that its practice of not forecasting costs of removal results in a lower revenue requirement and the FIRM Customers' recommendation to reflect a specific forecast for costs of removal should be rejected.

Position of ENMAX

ENMAX argued that TransAlta should use the liability method, effective 1 January 1999, and noted that its use is an accounting requirement in 2000. It also noted that booked deferred income taxes, calculated using current rates of income tax, are overstated relative to their timing differences. However it submitted that rather than reducing booked taxes applicable to future

[322] Tr.p.3945-3946
[323] Exhibit 193

periods on adjustment to the liability method, TransAlta should instead apply the excess timing differences to unbooked taxes and leave the booked tax amount unchanged. ENMAX suggested that using this approach would reduce the perceived risk regarding unbooked taxes to the level TransAlta is seeking and have the further benefit of not increasing the revenue requirement.

Mr. Johnson, witness for ENMAX, noted in Exhibit 205 that the unbooked deferred income tax could be reduced significantly by applying the liability method which allows the unbooked amount to be calculated at the current income tax rate of 28% rather than the 37.7% under which it was accumulated. He also noted that if the effective tax rate on the booked deferred income taxes is higher than the current federal income tax rate then additional benefits could be achieved.

Mr. Johnson assumed that the booked deferred income taxes were accumulated at an effective tax rate of 35%. Using current rates of income tax and reallocating TransAlta's proposed timing differences so that the amount of recorded deferred income taxes at 31 December 1998 did not change, he demonstrated that the unbooked and the booked deferred income taxes would reduce to $23.8 million and $35.1 million respectively on 31 December 2000. Mr. Johnson stated that this approach would benefit TransAlta and its customers and calculated the benefit to customers to be $22.8 million in 1999 and $25.7 million in 2000.

ENMAX further argued that, in applying the liability method, TransAlta should use an income tax rate that reflects the manufacturing and processing profits tax credit proposed in the 16 February 1999 Federal Budget.

Position of the FIRM Customers

The FIRM Customers recommended that TransAlta continue to follow the NDT method for 1999 and 2000 because there was no evidence to support any substantive changes in those years or thereafter in respect of TransAlta's cost recovery mechanisms or risks. They also stated that the NDT method was fair from an intergenerational point of view and that drawdowns of deferred income taxes should initially be made against recorded amounts.

The FIRM Customers were concerned that, because of TransAlta's forecasting practices, customers were not receiving the income tax benefits associated with costs of removal of plant and equipment. Therefore, they recommended that TransAlta reflect in its refiling a specific forecast for costs of removal and the related tax benefit or, alternatively, reflect the costs of removal, net of the tax shield, in its charge to accumulated depreciation.

Board Findings

The Board agrees that, beginning in 1999, TransAlta should adjust its federal income tax calculations to comply with the liability method for revenue requirement purposes and record future income tax liabilities and future income tax assets in its accounts. The Board considers that the change to the liability method will result, in total, in lesser amounts of booked and

unbooked future income tax liabilities at 1 January 1999 as compared to the aggregate amounts of booked and unbooked deferred taxes that would have been determined at that date without the change.

The Board also considers that TransAlta should adjust resulting booked and unbooked temporary differences in a manner that the amount of its recorded future income tax liability equals its recorded deferred tax balance at 31 December 1998, the latter amount of which represents past collections from customers in respect of income taxes applicable to future years.

The Board notes that TransAlta, in its Application, did not make any adjustments to its booked or unbooked deferred income taxes to comply with the CICA's recommendations under section 3465 of the Handbook and is not convinced that TransAlta has demonstrated that the adoption of the liability method will result in significant additional Large Corporations Tax.

The Board considers that the future income tax liability that is recorded by TransAlta as a consequence of its use of the NDT method should be drawn down (refunded to customers) prior to the amount that has not been recorded. As the use of the flow-through method would have an opposite result, i.e., in reductions of the unbooked future income liability first, the Board does not agree with TransAlta's proposed use of this method.

The Board concurs that TransAlta should use in its income tax calculations the proposed federal tax rate reductions for manufacturing and processing profits.

Based on the evidence presented, the Board considers that TransAlta's income tax forecasts do not require adjustments to include specific costs of removal and the related income tax benefits for the test years since TransAlta also does not forecast any increase to rate base due to specific costs of removal expected to occur during the test years. The Board notes that customers do receive income tax benefits by way of timing differences over the life of an asset since the forecast cost of removal is included in accounting depreciation charges but is not included in UCC until the time of retirement.

Accordingly, the Board directs TransAlta, in its refiling.

- Beginning in 1999, make the necessary adjustments in respect of its booked and unbooked federal deferred income tax balances to comply with the liability method, that is set out in the CICA Handbook section 3465.
- Allocate temporary differences to functions based on the method used to allocate net plant assets and any related liabilities to generation, transmission and distribution business units.
- Adjust the resulting booked and unbooked temporary differences in a manner that will provide for the future income tax liability that would otherwise have been recorded at 1 January 1999 to be equated with the booked deferred income tax balance at 31 December 1998 (refer to Exhibit 205).

- Calculate the federal income tax component of the revenue requirement in accordance with the liability method, and to continue to do so until the recorded future income tax liability has been discharged.
- Adjust the income tax rates used to include the proposed changes to the manufacturing and processing profits tax rate reduction as set out in Resolution 16 of the Federal Budget of 16 February 1999.

Should the proposed changes to the legislation be revised or not be enacted the Board will entertain an application by TransAlta to adjust the tax rate reduction accordingly.

The Board is satisfied that the above-approved method of computing the income tax component of the revenue requirement will provide TransAlta with an adequate before tax interest coverage factor. The Board also anticipates that, when it begins to take effect, the impact of the unrecorded future income tax liability on revenue requirement will not be significant and customers in the future will have rates that will include fair and reasonable charges for income taxes.

The Board, in Appendices 6 and 7 has provided an illustrative example of the results of the Board's findings using the evidence provided in Exhibit 205. The Board directs TransAlta, in its refiling, to provide the recalculated income tax using the same format as set out in Appendices 6 and 7 as a supplement to the normal income tax schedules.

(g) Hearing Cost Reserve

TransAlta's Hearing Cost Reserve account is summarized as follows:

TransAlta's Hearing Cost Reserve
($million)

	1996 Actual	1997 Actual	1998 Actual	1999 Forecast	2000 Forecast
Opening balance	0.6	1.5	3.4	4.2	3.7
Collected from customers	3.3	2.4	2.5	2.5	2.5
Payments	-2.4	-0.4	-1.6	-3.0	-5.5
Ending balance	1.5	3.4	4.2	3.7	0.6
Mid Year balance		2.28	3.80	3.95	2.15

Source: TransAlta Evidence, Tab 6.4; CCA.TAU-65a

TransAlta submitted that there is sufficient forecast regulatory activity such that the annual provision of $2.45 million is still appropriate.

Position of the FIRM Customers

The FIRM Customers noted that the Hearing Cost Reserve account has a positive balance. Since it is included in TransAlta's no cost capital, customers should gain the benefit of a lower return.

In 2000, TransAlta forecast a mid year balance in the generation business unit of $1.2 million.[324] This translates into around 56% of the total mid year balance for the account. Using this ratio, the generation business unit would have about $0.3 million (56% x $0.6 million) of the rate hearing reserve account at the end of 31 December 2000. However, TransAlta does not indicate how the excess portion related to generation will be handled at the end of 2000. The FIRM Customers considered that the most appropriate method would be to flow this amount into the Balancing Pool. The FIRM Customers recommended that the Board direct TransAlta to flow the portion of the hearing cost reserve account related to generation into the Balancing Pool at the end of 2000.

Position of ENMAX

In Section 6.4 of its Application, TransAlta provided a schedule entitled "Continuity of Hearing Cost Reserve." The closing balance on 31 December 2000 is $600,000 indicating that customers have over contributed. During cross-examination, TransAlta was asked to explain why the balance was not zero at 31 December 2000. The response was:

> Essentially, it is just because it is not a significant balance relative to the other years.[325]

Exhibit 92 (last page) provides the allocation of the Hearing Cost Reserve as 30% generation, 10% transmission and 60% distribution. TransAlta confirmed this allocation was still appropriate for 2000.[326] TransAlta clarified their position on the allocation of the ending balance in this account as follows:

> ... we feel that it probably is more appropriate just to have the hearing reserve amount just flow into the T and D hearing reserve and be retained for future regulatory hearings. It is a small amount, and rather than have it somehow have to be accounted for in some other ways, since it is a small amount, just to treat it as a hearing reserve, but it won't be specifically used for generation hearings after that. It will be used for T and D hearings.[327]

---

[324] TransAlta Evidence, Section 2.1(Revised), Schedule G-3
[325] Tr. p.3899
[326] Tr. p.3900
[327] Tr. p.3968

The electric utility industry is entering into a new era in 2001. Effective 1 January 2001 TransAlta GENCOs will have different customers than on 31 December 2000. The entire industry should ensure that the transition into the new era is as clean as possible with no loose threads left behind. As a result, it is ENMAX's position that the balance in the Hearing Cost Reserve account should be forecast at zero for 31 December 2000. This will ensure a clean starting point for all business units.

In the alternative, should the Board consider that the balance in this account does not have to be zero at 31 December 2000 then the Board must deal with the treatment of the balance. TransAlta's proposal to transfer the balance to the transmission and distribution business units in 2001 is not appropriate as generation customers would forfeit the 30% of the funds they contributed to this account. It is recommended that, at a minimum, the generation portion of this balance be refunded in 2000 to reflect industry changes taking place on 1 January 2001.

Position of TransAlta

TransAlta submitted that its forecast balance of $0.6 million is reasonable having regard to the length and complexity of the regulatory process since the time of filing. The more important issue is the disposition of the actual hearing cost balance at the end of 2000. TransAlta submitted that its proposal[328] to transfer the entire balance to Transmission and Distribution for future regulatory hearings is the most simple and practical approach and should be accepted by the Board.

Board Findings

The Board agrees with TransAlta that the annual provision of $2.45 million is appropriate and that the forecast balance of $0.6 million is reasonable given the uncertainty of the length and complexity of regulatory activity required to take place prior to 1 January 2001. The Board also agrees that the more important issue is the disposition of the actual hearing cost reserve balance at the end of 2000. The Board agrees that the most simple and practical approach is to transfer any positive or negative balance to the TRANSCO and DISCO functions. Accordingly, the Board directs TransAlta to transfer any positive or negative balance in the Hearing Cost Reserve at the end of 2000 to the TRANSCO and DISCO functions and report on the transfers at the next GTA for TRANSCO and DISCO.

(h) Pension Reserve

Effective 1 July 1998, TransAlta changed its funding for both the defined benefit (DB) pension plan, and the defined contribution (DC) pension option. TransAlta will now be responsible for all funding of the DB pension option. For the DC option, TransAlta will contribute both the employee (4%) and employer (6%) portion toward each employee's DC account balance.

[328] Tr. p.3968

TransAlta stated there were also three other improvements:

- All retirees and their beneficiaries will receive a one-time 8% increase in their pension benefit.
- Future cost-of-living increases for retirees and their beneficiaries in the DB option will be fixed at two per cent per year, thus providing greater certainty for those individuals.
- Pension benefits that have been promised by TransAlta but which exceed the *Income Tax Act* funding limits (i.e. supplemental pensions) will be paid from pension surplus when they exist, or from TransAlta's general revenues if there is no surplus.

TransAlta proposed these improvements for several reasons, including:

- Strengthen TransAlta's competitive position as an employer of choice. These improvements ensure the overall benefit and compensation package is competitive in the Calgary and Alberta market.
- Ensure that long service employees who helped build the company and are now enjoying their retirement, as well as their beneficiaries, also share in the benefits of the pension plan improvements.
- Ensure the pension benefits promised by TransAlta in excess of funding limits will be more securely funded.

TransAlta filed a revised schedule of Continuity of Pension Liability[329] that was testified to by Mr. Veres. Mr. Veres explained[330] that the closing balance of pension liability has risen from $16 million in 1996 to $25.8 million in 1999 and $22 million in 2000 as a result of the liabilities associated with the supplemental pension plan. With respect to the registered pension plan, the closing balance of negative $9.4 million for the basic pension plan and positive $6.5 million for the DC plan result in a negative balance of $2.9 million in this account; that is, contributions to the plan by the end of 2000 will have exceeded the amounts collected from the customers by $2.9 million. Offsetting this amount is a $24.9 million closing balance for the supplemental plan for 2000, resulting in the closing balance total pension liability of $22 million.

With respect to TransAlta's change to a non-contributory pension plan, with TransAlta covering what had been the employee's 4% contribution, Mr. Way made the following comment:

> Mr. Holgate, I just might add Mr. Janke was actually prepared to speak to that aspect of how the company's benefits had fallen behind, and according to a survey of, I forget, it was something like 20 companies -- he showed me a graph

[329] Exhibit 58
[330] Tr. p.3913, p.4291

that he had that we were well down at the bottom of that graph. And by making this adjustment, we didn't pull up to the mid-point, but we pulled up at least so that we weren't at the bottom anymore. But this was seen as an adjustment to the compensation level competitive with the market.[331]

The following information was provided in response to ENMAX.TAU-64 on the increase in revenue requirement caused by the 4% increase:

($Millions)

	Gen	Trans	Dist	Corp	Total
1999 Payroll by Business Unit	38.7	12.6	36.2	24.1	111.6
Funding of Employee's share @ 4%	1.5	0.5	1.4	1.0	4.5

In response to questioning by Mr. Holgate, Mr. Veres confirmed that customers are benefiting from the pension surplus through reduced pension expenses as the pension surplus is amortized into pension expense over the "Employee Average Remaining Service Life."[332]

Position of ENMAX

ENMAX noted that TransAlta's revised continuity schedule for its Pension Reserve account contained the pension expense and contributions for each pension plan. A DC plan was initiated in 1997. The DC plan shows a pension expense of $6.5 million for that year. However, there is no corresponding contribution amount for that year. Historically, a reserve balance for pension costs was introduced to essentially capture the differences between the funding and the accounting of pension costs. These differences arose out of DB pension plans for which the actuarial funding requirements could be substantially different than the pension expense. However, with the introduction of the DC plan in 1997, the differences between funding and expense disappear. By definition the contribution is the expense for DC plans. TransAlta acknowledged that the expense and the contribution are the same and agreed that as a result there is no uncertainty regarding the cash contributions for TransAlta's DC plan.[333] It is simply a matter of applying a factor to the applicable payroll. That factor was increased by two-thirds in 1998, from 6% to 10%.

Under a DC plan, the pension expense for each year should match the contributions that are necessary for the plan. According to the pension continuity schedule, that is the case for the years 1998 through 2000. There was, however, no pension contribution for 1997. Despite this TransAlta has, for the purpose of this schedule, included the $6.5 million as a pension expense for that year. The consequence is a closing balance in 2000 in the amount of $6.5 million, which

[331] Tr. p.3925
[332] Tr. p.3936
[333] Tr. p.3916

bears no relationship to any contribution requirement. Between 1997 and 2000 TransAlta would have collected $28.9 million to meet a contribution requirement of $22.4 million; $6.5 million more than it needs for funding purposes.

Moreover, because of the switch to the DC plan by 85% of TransAlta employees[334] there is no need for the associated costs to flow through a pension reserve. This is illustrated in the case of EPGI/EPTI. EPGI/EPTI and their predecessors are long time participants in the Local Authorities Pension Plan.[335] The pension expense is simply a percentage of the eligible payroll. As such, EPGI/EPTI and its predecessors never had the need for a pension reserve account. The obvious reason was that there was no difference between the funding and the expense. For TransAlta's purpose, the $6.5 million balance in the DC plan is unnecessary. ENMAX recommends that the Board should require that the $6.5 million balance be refunded to the entitled discos as part of the current test period.

In addition to the Basic DB and the Basic DC plans, TransAlta also maintains a Supplemental Pension Plan. Its purpose is to provide additional pension benefits in excess of limits set by the *Income Tax Act*. This plan is unfunded and supplements pension benefits for those employees earning in excess of $86,000 for the DB Plan and $106,000 for the DC Plan.[336] Consequently, there is a staggering increase in the pension liability beginning with $5.6 million in 1996[337] and growing to $24.9 million by the end of 2000.

The limits placed by Revenue Canada are those which determine what would be deductible for tax purposes. The consequence is that the cost to power purchasers for the supplemental pension and post employment benefits are substantially higher because of additional tax cost.

ENMAX submitted that the Revenue Canada limits are reasonable. If TransAlta wishes to attract employees with additional compensation in the form of a supplemental pension plan, then it should be allowed to do so. However, like certain of the incentive compensation, those amounts should be paid out of TransAlta's profits and not the regulated cost of service. That would provide the appropriate incentive for efficiencies and productivities while not burdening customers with out of control benefits.

The pension assumptions are contained in the regular actuarial assessments. When asked for a copy of the most recent assessment, despite common practice in prior GTAs, TransAlta claimed it was confidential.[338] During the hearing TransAlta advised Intervenors and the Board that the assumed investment return is 7.5%. By contrast the investment returns actually enjoyed by TransAlta's pension over the last four years were far greater, ranging between a low of 14.2%

[334] TransAlta Evidence, Volume 1, Tab 6.1
[335] Tr. p.540
[336] Tr. p.3912, p.4265
[337] Tr. p.3920, p.3921
[338] CCA.TAU-68, Tr. p.3914

and a high of 19.9%.[339] The 7.5% assumption is excessively conservative in light of recent history. The Board, in Decision U97065, expressed great concern with overly conservative assumptions and found that, for rate-making purposes, it was inappropriate to allow any further increases in the deferred pension account in excess of a $13.0 million balance.[340] Under TransAlta's proposal, that balance is expected to balloon to almost twice that amount in 1999 ($25.8 million) and maintain the extraordinary high levels in 2000 ($22.0 million).[341]

In summary, ENMAX submitted that the $6.5 million of excessive expense that has been charged to customers in the DC pension plan should be refunded to customers within the test period. Further, ENMAX submitted that the costs of the supplemental pension plan should be covered by excess profits of TransAlta to match with incentives and still achieve adequate attraction for a quality workforce. In the alternative, the Board should disallow the sudden and dramatic increases in the supplemental balances on the grounds that it far exceeds the Board's established guideline. The Board should maintain the balance in the pension account at the $13 million level it previously determined.

Position of the FIRM Customers

TransAlta detailed several pension plans in the revised Continuity of Pension Liability Schedule. Included is a DC plan showing a closing balance in the reserve account of $6.5 million in each of the test years. Apparently, this plan was initiated in 1997 when a provision for the expense was made without any offsetting contribution by TransAlta. Since then, the balance of $6.5 million has been carried forward every year.

TransAlta acknowledged that there is no uncertainty as to the cash contributions required by the company each year and it would match the pension expense.[342] The FIRM Customers submitted that, given this, there is no need for a reserve of any amount for the DC plan. Therefore, the FIRM Customers recommended that the $6.5 million balance forecast to continue in 1999 and 2000, should be reflected as a reduction in pension expense and returned to customers through the rates.

Position of EAL

The move to a fully non-contributory pension plan is acknowledged by TransAlta to have the effect of giving each employee a 4% raise.[343] EAL suggested that this, combined with the applied for general escalation in salaries and wages of 3%[344] implies that TransAlta is asking for

[339] Exhibit 129, Tr. p.3937
[340] Decision U97065, p.516
[341] Exhibit 58
[342] Tr. p.3916, p.3918
[343] Tr. p.3924
[344] TransAlta Evidence, Section 3.2.2.1

the Board to approve a 7% salary increase for its employees. EAL submitted that this is an unreasonable escalation given recent inflation.

Further, an approved change to a non-contributory pension plan sets a precedent which would allow all regulated utilities to apply for a change to a non-contributory pension plan. Other regulated utilities would have to, to maintain competitiveness with TransAlta. This would have a cascading effect of increasing rates substantially for all consumers by far more than the increase requested by TransAlta.

EAL noted that the burden of proof for cost increases rests on the applicant. TransAlta cited that the salary increases would "ensure the overall benefit and compensation package is competitive in the Calgary and Alberta market."[345] TransAlta admitted that was the reason for the applied for change in contribution policy.[346] TransAlta also cited a study that supposedly supported their position on the "non-competitiveness" of their current salary structure, however, this report was not in their application, and it was neither produced nor tested in the hearing. They have not done an explicit study on the competitiveness of their pension plans.[347] EAL submitted that neither the 4% raise as a result of the movement to a non-contributory pension plan, nor the salary escalation of 3% have been supported, and these costs should not be allowed to be recovered in the revenue requirement of TransAlta.

TransAlta admitted that their DB pension plan has a surplus.[348] This implies that the rate-payers have paid more than they should have as a result of the good performance of the assets within the plan.[349] The proposed 8% increase to retirees and their beneficiaries will lower the surplus by increasing the obligations of the DB plan.[350] The benefits to retired TransAlta employees were agreed to by those employees at the time they worked for TransAlta. An arbitrary increase in the benefits at this point (once the employees are retired) is simply a gift from TransAlta to those retired employees. There is no consideration received by TransAlta for these increased benefits. Further, because the surplus is extra money that was paid by rate-payers, TransAlta is essentially gifting excess that should rightly be refunded to the rate-payers.

The fixed 2% increase in perpetuity for plan benefits should also be disallowed. This increase again has the effect of increasing the present value of the DB plan obligations, in a similar fashion to the 8% increase. Again, once it is approved there is no chance of lowering the benefits, and moving to a fixed 2% cost of living increase creates additional fixed costs for the pension plan, that if in deficit would have to be recovered from rate-payers. Again, these

[345] Tr. p.3927
[346] Tr. p.3927-3928
[347] Tr. p.3928, l. 22
[348] Tr. p.3926
[349] Tr. p.3932
[350] Tr. p.3933

improvements are gifts to retired TransAlta pensioners with no consideration to TransAlta or rate-payers.

EAL submitted that instead of increasing plan liabilities to reduce the DB pension surplus, TransAlta's revenue requirement should be reduced by the amount of the pension expense attributable to the DB pension plan until such time as the pension plan's assets and liabilities are more closely matched.

The proposal put forth by TransAlta increases both costs and risks for rate-payers. Were the additional benefits allowed, and future asset returns were poor or even negative, TransAlta may be forced to recover additional money to ensure that the pension remained properly funded. Once the benefits are approved, there is likely little chance that they will be reduced in the future. If TransAlta is allowed to move to a non-contributory plan, any future under-funding will be fully the responsibility of the company, and through them the rate-payers.[351] Increasing benefits will increase costs for rate-payers, who will receive nothing in return. The move to a non-contributory pension plan provides an excessive salary increase to TransAlta with no substantiation of the allegations that TransAlta's salary structure is currently non-competitive.

EAL noted TransAlta's argument that customers are benefiting from the pension surplus through reduced pension expenses as the pension surplus is amortized into pension expense over the Employee Average Remaining Service Life. The issue is not whether customers benefit, the issue is whether the benefit to customers is sufficient in the circumstances.

EAL submitted that, in order for customers to receive an appropriate share of the benefit from a pension surplus paid for by those customers, the following recommendations should be accepted by the Board:

- Disallow the revenue recovery of the incremental 4% pension costs resulting from the move to a non-contributory pension plan.
- Disallow the one-time 8% escalation of pension benefits to retired employees.
- Disallow the move to a fixed 2% benefits increase.
- Provide customers a contribution holiday for the DB pension plan contributions until such time as the plan's assets and liabilities are more closely matched.

Position of TransAlta

TransAlta submitted that its pension expense had been demonstrated to be reasonable.

ENMAX and the FIRM Customers in their submissions claimed that the deferral account is over-stated by $6.5 million because of a mismatch in 1997 between the amount recorded by TransAlta as an expense and the amount contributed by TransAlta in that year. Although ENMAX

[351] Tr. p.3934

characterizes the $6.5 million as "excessive expense that has been charged to entitled discos in the DC plan," in fact the $6.5 million expense in 1997 has been properly recorded and it is only the amount contributed by TransAlta that could be in dispute.

In claiming the $6.5 million refund, ENMAX has chosen to focus only on the DC portion of the Basic Pension Plan. When including the DB portion of the Basic Pension Plan, by year end 2000, the company will have contributed $2.9 million more than it has collected from its customers.[352] Accordingly, if the Board employed the ENMAX and the FIRM Customers argument, it would be necessary for the Board to increase the revenue requirement in the year 2000 by $2.9 million even after excluding the $6.5 million contribution in 1997.

With respect to the Supplemental Pension Plan, ENMAX conceded that the company should be allowed to "attract employees with additional compensation in the form of a supplemental pension plan" as long as "those amounts should be paid out of TransAlta's profits and not the regulated cost of service." In the matter of the Supplemental Pension Plan, ENMAX chose to ignore Board Decision U97065 at page 515 which stated:

> The Board considers that these plans form a part of the employee compensation package and that associated costs have been included in prior years' revenue requirements. Accordingly, the Board considers it appropriate that the expenses and contributions associated with the supplemental pension and post-employment benefits plans be included in the deferred pension account.

With respect to the pension assumptions employed by TransAlta, ENMAX maintained that an assumed investment return of 7.5% is "excessively conservative in light of recent history" and that the Board in Decision U97065 "found it was inappropriate to allow any further increases in the deferred pension account in excess of a $13 million balance."[353] The balance of $22.0 million in the deferred pension account in 2000 is exclusively attributable to the Supplemental Pension Plan. Since there are no assets associated with the Supplemental Pension Plan liabilities,[354] the amount in the deferred pension account for the Supplemental Pension Plan is completely independent of pension assumptions employed by TransAlta relative to the DB component of the basic pension plan. In other words, whether TransAlta assumed a 7.5% return for its DB plan or a 25% return would have no relevance or impact on the closing balance pension liability attributed to the Supplemental Pension Plan.

In cross-examination, Mr. Veres also addressed ENMAX's assertion that "the 7.5% assumption is excessively conservative in light of recent history":

[352] Tr. p.3913
[353] ENMAX Argument, p.61
[354] Tr. p.3911

Q. There is obviously no guarantee that those kinds of returns will continue indefinitely into the future?

A. I think one only has to look at the third quarter of 1998 when the equity markets lost 23 ½ % to know these kinds of returns are precarious at best.[355]

TransAlta further submitted that ENMAX had failed to provide any evidence that the 7.5% return employed by TransAlta for the DB portion of the total pension expense is excessively conservative. ENMAX had also failed to properly portray that the 7.5% return applies only to the DB component of pension expense, a small portion of total pension expense.

EAL attacked TransAlta's pension expense on a number of grounds, and recommended that the change to the non-contributory pension plan be disallowed and the 2% increase given retirees be reversed. EAL also attacked the "salary escalation of 3%." EAL objected to these items as being "excessive." TransAlta noted that the forecast escalation rate for labour was 1.6%. Transmission and Distribution included an additional 1.4% relating to merit increases.[356] In making this recommendation, EAL ignored the dramatic downsizing effected by TransAlta in recent years, the resultant increased workloads of remaining employees, the efforts of new entrants (such as EAL) to hire qualified staff from the utilities and the evidence of Mr. Janke that TransAlta's employees are below the mid-point of the benefits survey conducted by TransAlta.

TransAlta submitted that there is no evidence to suggest that TransAlta's pension program is unreasonable in any respect and EAL's arguments should accordingly be rejected.

Board Findings

The Board notes that TransAlta determines pension expense and pension liability separately for each of the following pension plans:

- Basic DB Plan
- Basic DC Plan
- Supplemental Plan

The basic DB plan has a surplus of $38.4 million. TransAlta is requesting a negative pension expense of $1.7 million in 1999 and negative $8.5 million in 2000. The Board notes that customers are benefiting from the pension surplus through reduced pension expenses as the pension surplus is amortized into pension expense over the "Employee Average Remaining

[355] Tr. p.3932
[356] CCA.TAU-25

Service Life."[357] The closing balance of the liability reserve is negative $0.9 million in 1999 and negative $9.4 million in 2000.

By definition, the basic DC plan has no surplus or liability. TransAlta is requesting a pension expense of $7.7 million in 1999 and $8.1 million in 2000. The closing balance of the liability reserve is $6.5 million in 1999 and $6.5 million in 2000.

The Board agrees with ENMAX and the FIRM Customers that there is no need for a $6.5 million balance in the pension liability reserve for the basic DC plan since the cash contributions required by the Company each year match the pension expense. However, the Board does not agree that the money should be returned to customers during the test period (i.e. reduce pension expense by $3.25 million for each of 1999 and 2000). Rather, the Board notes that the closing balance in the DB liability reserve is negative $9.4 million. The Board considers that the positive $6.5 million in the DC liability reserve should be used to offset the negative $9.4 million in the DB liability reserve. Accordingly, the Board directs TransAlta, in its refiling, to transfer $6.5 million from the DC liability reserve to the DB liability reserve.

The Board notes that the supplemental plan has a liability of $23.7 million and the post-retirement plan has a liability of $17.2 million for a total of $40.9 million as of 31 December 1998. TransAlta is requesting a pension expense of $5.4 million in 1999 and $5.6 million in 2000. The closing balance of the liability reserve is $20.2 million in 1999 and $24.9 million in 2000.

The pension expense has been calculated assuming that TransAlta:

(1) pays both the employee contribution of 4% and employer contribution of 6%;
(2) pays a perpetual 2% cost-of-living increase for retirees and their beneficiaries
(3) pays all retirees and their beneficiaries a one-time 8% increase in their pension benefits.

The Board agrees with EAL that TransAlta's payment of the employee contribution effectively constitutes a pay increase of 4%. The Board in a previous section of this Decision has already approved a 3% increase in salaries to cover inflation and merit components for 1999 and 2000. The Board notes that Mr. Janke was prepared to speak to a survey conducted by TransAlta which purportedly demonstrated that TransAlta's employees are below the mid-point of compensation packages even with the additional 4% increase. However, the Board also notes EAL's comment that:

> ...this report was not in their application, and it was neither produced nor tested in the hearing. They have not done an explicit study on the competitiveness of their pension plans[358]

[357] Tr. p.3936

The Board observes that the TransAlta compensation survey Mr. Janke was prepared to speak to was neither spoken to by Mr. Janke nor entered as evidence. The Board, in the absence of the benefit of the production and testing of the TransAlta survey, is uncertain whether the survey was based on TransAlta compensation levels before or after the requested 3% increase in salaries which has now been granted by the Board. Further, the Board has no knowledge of whether the 20 companies surveyed constitute an appropriate comparative sample.

Notwithstanding the lack of complete supporting evidence, the Board is prepared to grant an additional 2% payment for employee contributions in the pension expense for the pension plans. The Board considers that the overall increase of 5% in compensation (3% salary and 2% pension contribution) and the Board's approval of TransAlta's incentive compensation plan will assist in keeping TransAlta's overall benefit and compensation package competitive in the Calgary and Alberta markets during 1999 and 2000. The Board is prepared to revisit this issue at the time of the next GTA and make any further adjustments as required and supported by representative comparative compensation evidence.

Accordingly, the Board directs TransAlta, in its refiling, to only include the effect of an additional 2% payment for employee contributions for the pension expense, pension contributions and pension liability for the pension plans as well as consequential effects on operating expenses and capital expenditures by business unit. The Board notes that TransAlta is free to maintain the full 4% benefit through shareholder funding if it so chooses.

The Board considers as reasonable and, therefore, approves a 2% cost-of-living increase for retirees and their beneficiaries in the pension plans for 1999 and a further 2% cost-of-living increase for 2000.

The Board denies the request to implement an additional 2% cost-of-living increase per year beyond the year 2000. The Board considers that any future cost-of-living increases should be dealt with in future GTAs consistent with prevailing circumstances in future test years. Again, the Board notes that TransAlta is free to maintain this benefit through shareholder funding if it so chooses.

The Board also approves the assumed 7.5% investment return included in the DB pension assumptions.

The Board agrees with EAL that:

> The benefits to retired TransAlta employees were agreed to by those employees at the time they worked for TransAlta. An arbitrary increase in the benefits at this point (once the employees are retired) is simply a gift from TransAlta to those

[358] Tr. p.3928, l.22; EAL Argument, p.45

> retired employees. There is no consideration received by TransAlta for these increased benefits. Further, because the surplus is extra money that was paid by rate-payers, TransAlta is essentially gifting excess that should rightly be refunded to the rate-payers.[359]

The Board denies TransAlta's request to include the additional 8% one-time increase to pension benefits. The Board directs TransAlta, in its refiling, to remove the effect of the additional 8% one-time increase to pension benefits from the pension expense, pension contributions and pension liability for the pension plans as well as consequential effects on operating expenses and capital expenditures by business unit. The Board notes that TransAlta is free to maintain this benefit through shareholder funding if it so chooses.

(i) Self-Insurance Reserve

The Board directed TransAlta, at the time of the next GTA, to:

> provide evidence to substantiate the continuance of this reserve in light of the new industry structure.[360]

TransAlta, in response to the above Board Direction, proposed to discontinue the Reserve for Self-Insurance (the "SIR"). As testified to by Mr. Waiand, TransAlta proposed to rebate the remaining reserve amounts to customers in 1999 and 2000 and to replace the reserve with additional insurance coverage with deductibles similar to those currently covered by the SIR. In this way the insurance reserve, claims against which have largely related to the Generation business, will be returned to customers during the term of the current regulatory regime (ending 31 December 2000) being the same regime during which the reserve was established.

TransAlta proposed to eliminate the previously approved SIR and rebate the remaining reserve amount to customers in 1999 and 2000. In its place, TransAlta proposed an insurance program with reduced deductible levels.

TransAlta's reasons and position on the elimination of the SIR are as follows:

[359] EAL Argument p.45
[360] Decision U97065; Board Direction TAU-15

- That a centralized, customer-funded reserve does not meet with longer-term objectives in light of the "development of the PPAs."[361]
- Concern that it was unclear how any surplus or deficit in the SIR would be handled in the PPA period, and therefore, TransAlta needed to get rid of the SIR prior to 2001.[362]
- The continued use of the SIR is inappropriate with the separation of Utility costs into the different business units.
- Need to minimize the opportunities "to obtain rate relief for significant damaging events and having the Utilities responsible for managing the costs over the longer term."[363]
- A concern that a number of events could occur in the test years that would force the reserve into a negative balance.[364]

TransAlta's proposal is to:

> [increase] the annual insurance expense in order to purchase insurance policies with similar deductibles to that being covered by the SIR today. In exchange, the customer is then able to transfer the risks it retained with the reserve to others.[365]

TransAlta's proposal to eliminate the SIR is in direct contrast to EPGI, EPTI and AE who propose to continue their equivalent SIRs.

TransAlta's insurance expense forecast is as follows:

	($ million)	
	1999 Forecast	**2000 Forecast**
Generation (TransAlta Evidence, Schedule 2.3.6)	5.6	5.8
Transmission (TransAlta Evidence, Schedule 3.2.6)	0.3	0.3
Distribution (TransAlta Evidence, Schedule 4.2.6)	0.4	0.4
Corporate Services (TransAlta Evidence, Schedule 5.1.6)	0.4	0.4
Totals	**6.7**	**6.9**

Insurance expense has historically been accounted for in Corporate Services and was provided in the filing as follows:

[361] TransAlta Evidence, Tab 6.4
[362] Tr. p.3873-3874
[363] TransAlta Evidence, Tab 6.4
[364] Tr. p.3874
[365] TransAlta Evidence, Section 6.4

	($ million)
1996 Recorded	5.7
1997 Recorded	5.7
1998 Current Estimate	3.8

Source: TransAlta Evidence, Schedule 5.1.6

The Self-Insurance Reserve Continuity Schedule indicates there were annual contributions of $1.0 million to the SIR in 1997 and 1998.[366] TransAlta is proposing to amortize the $4.8 million 1998 closing balance in the reserve through a credit to insurance expense of $2.4 million per year for 1999 and 2000.

To place the self insurance requirements in perspective, the FIRM Customers noted claims against the reserve for 1995, 1996 and 1997 were $0.89, $1.79 and $1.02 million, respectively, or an average of $1.2 million per year.[367]

In this filing, TransAlta indicates additional insurance costs of $3.7 million per year are proposed. TransAlta goes on to state these additional costs would include:

- Replacement of the self-insurance reserve at a cost of $2 million per year. This is to provide coverage for a deductible of $25,000 for property and $100,000 for liability. This is an increase of $0.8 million over the last three years SIR average claims of $1.2 million, described above;[368]
- Additional insurance for generation forced outages. This coverage, at a cost of over $1 million per year, would provide for potential generation expense, such as UOV payments. TransAlta is proposing this addition even though a legislated TSR process exists; and[369]
- New insurance for third party liability for a breach at one of the hydro dams. TransAlta indicates this coverage was not previously in place. The associated cost is $1.5 million per year.[370]

Position of the FIRM Customers

The FIRM Customers have several concerns with TransAlta's proposal. First, the cost of the replacement insurance for the SIR is roughly $2 million per year whereas the historical cost of claims against the reserve averages much less at $1.2 million per year. Therefore, the cost of replacement insurance is greater than the benefits consumers are likely to see. Second, the

[366] TransAlta Evidence, Section 6.4
[367] TransAlta Evidence, Section 6.4
[368] TransAlta Evidence, Section 5.1; Tr. p.3878-3879, p.3890
[369] Tr. p.3884, p.3890
[370] Tr. p.3890

additional insurance for forced outages is, in effect, double insuring this category of risk since the intent of the legislated TSR is to provide cost recovery for this type of occurrence. Finally, TransAlta does not provide any justification in its filing for the proposed insurance for hydro facilities. We note, TransAlta has not required this type of insurance in the past and its general insurance would appear to provide third party liability coverage.

Treatment of Self-Insurance Reserve

The FIRM Customers do not accept the positions advanced by TransAlta to support the elimination of the SIR in the test years. The issues raised by TransAlta regarding the move to the PPA world and customer funded reserves not meeting the objectives of this new world can be dealt with in the new world. As with other carry-over items, balances remaining in the SIR can be dealt with through the Balancing Pool after 2001. Based on this and the fact historical experience indicates the costs of the commercial insurance proposed for 1999 and 2000 will likely exceed any benefits consumers may receive, the FIRM Customers submitted it is in the best interest of ratepayers to have TransAlta continue to self-insure in the test years.

In terms of the separation of costs by business unit, the FIRM Customers note, the majority (90-95%) of the SIR costs are generation-related. Consequently, the separation of costs by business units should not be considered a factor in the elimination of the SIR. Claims by business units have been identified over the past few years without a problem.[371]

With respect to the reserve balance going negative, we submit this is the risk customers have undertaken since the SIR concept was put into place. The FIRM Customers noted, based on the average claim experience over the last three years of $1.2 million, the SIR balance of $4.8 million at 31 December 1998, has about 4 years of "life" left. Based on a balance of probabilities, it does not appear likely the reserve amount as at 31 December 1998, will be depleted by 31 December 2000.

In summary, the FIRM Customers recommended that the Board direct TransAlta to continue the self insurance program for 1999 and 2000 at the currently approved levels and at the end of 2000 transfer any remaining balance into the Balancing Pool.

Replacement Insurance for Self-Insurance

The insurance purchased by TransAlta to replace the SIR should be disallowed for 1999 and 2000 as duplicating the self-insurance. Accordingly, the FIRM Customers recommended the $2 million in annual premiums be removed from insurance expense.

Additional Insurance for Generation Forced Outages

The FIRM Customers are concerned TransAlta is including approximately $1 million for premiums with respect to coverage for outages and unit obligation value payments. Apparently,

[371] Tr. p.3874

TransAlta has carried such insurance since 1997. TransAlta explains the need for the coverage as follows:

> The view that we took was that the TSR, given that we would have to go through a hearing process to recover the amounts and the outcome of that is obviously unclear, that we thought it would be more prudent to put in place insurance to cover off that risk to allow us to satisfy our obligations. We have included in our forecast insurance expense premiums to do that.[372]

And further:

> No, we concluded that it would be more prudent to actually buy insurance to fund our obligations in the event of a unit outage.[373]

The TSR does not cover the physical damage costs but may be available to cover the "obligation to hedge the costs of the inability to supply energy." [374]

The FIRM Customers considered that the reluctance of TransAlta to go before the Board to recover amounts that should be eligible under the TSR is not an adequate reason to seek recovery of additional insurance expense from customers. If such amounts are indeed recoverable under the TSR, TransAlta will effectively be insuring against this loss twice, namely once through the insurance and again through the TSR. Further, TransAlta's proposal would be contrary to the current Board approved treatment in U97065, where no costs are included in the Unit Reservation Price associated with the costs of generation outage i.e. costs recoverable through the TSR.

The FIRM Customers considered that this additional insurance should not be charged to consumers and recommended that the Board direct TransAlta to remove the forecast premiums from TransAlta's revenue requirement.

New Insurance for Third Party Liability for Breach of Hydro System
As discussed above, there is very little information on the record regarding the sudden need for the new insurance. The FIRM Customers recommended that the Board disallow this insurance on the basis it was not required previously and there appears to be little reason for it now.

Position of ENMAX

Prior to this application, TransAlta has maintained a "SIR". In 1999/2000 TransAlta is proposing that the SIR be replaced and the balance remaining in the reserve be used to buy down current

[372] Tr. p.3882
[373] Tr. p.3883
[374] CCA.TAU-67(d)

insurance deductibles and purchase additional insurance. According to the proposal the reserve will be liquidated before 2001 when the PPAs are scheduled to take effect.[375]

Tab 6.4 of the application shows the projected reserve balances as the $4.8 million forecast at the end of 1998 is liquidated to buy more insurance. TransAlta confirmed that if the historical rate of claims against the reserve were to be the same in future there would be almost 4 years worth of funds before the reserve is depleted.[376]

TransAlta offers three reasons why it wishes to eliminate the reserve.

- The first is the development of the PPAs. TransAlta states that it concluded that there is a significant risk that the SIR could be still in existence at the end of 2000, could grow by some amount, or alternatively due to a number of claims the reserve could go into a deficit. As a result TransAlta says it was unclear how that surplus or deficit, were it to exist, would be returned to or collected from customers.[377] This position is inconsistent with the position taken by TransAlta on balances in the RAR account for small power where it is apparently quite acceptable to TransAlta that amounts be refunded via the Balancing Pool after 2000.
- The second reason given for eliminating the reserve, as it relates to transmission, is that virtually all the utilization of the reserve is for generation. As well, given the separation of utility costs into different business units TransAlta stated that it is now possible to acquire individual insurance contracts covering the individual business units.[378] This would seem to be a distinction without a difference as the problem is simply one of allocation to the business units. If it makes economic sense for some or all business units to purchase insurance on their respective property collectively, the appropriate course of action is to buy insurance collectively and allocate the costs among the business units. In fact TransAlta agreed it would be possible to have a centralized reserve with an allocation made to business units.[379]
- The third reason given for replacing the reserve is to provide clarity as to how TransAlta might recover a deficiency from power purchasers.[380] This reason further demonstrates the inconsistency of treatment between a deficiency to be collected from customers and a refund due customers. TransAlta suggested that if the SIR is eliminated, there is virtually no risk of any unused balance at the end of 2000. According to TransAlta this suggestion reduces the risk to customers for the two-year period.[381]

[375] TransAlta Evidence, Tab 6.4
[376] Tr. p.3872
[377] Tr. p.3872
[378] Tr. p.3873
[379] Tr. p.3874
[380] Tr. p.3874
[381] Tr. p.3876

The risk reduction comes at a great price. The issue of concern to ENMAX is whether the price of the risk reduction is economic. The increased insurance expense in 1999/2000 is $3.7 million.[382] Of this the additional cost to cover off the same risks inherent in the SIR is said to be about $2 million per year.[383] TransAlta admitted that its proposal was to spend $2 million per year to cover off a risk which has averaged $1.2 million per year, as well as to cover off the risks of any SIR events during the period. This change in the SIR appears to be as a result of the coming PPAs. Although the PPAs are planned, they do not take effect during the test years. Given that the historical record indicates the SIR claims are less than the premiums, it still appears less costly to self-insure for a component of insurance than to buy down deductibles. It may well be appropriate for individual plants to carry their own insurance in the PPA world but not prior to 2001. TransAlta appears to be incurring additional insurance expense as part of their risk management strategy for the benefit of the future.[384] Any such reduction in risks should be reflected in assessing TransAlta's overall risk of doing business.

In terms of the accounting treatment for claims for replacing equipment, TransAlta agreed that if a deductible relates to a certain class of asset it would "perhaps" be appropriate to defer and amortize instead of expense the costs.[385] ENMAX supports this approach as a better matching of the costs and the revenues associated with an asset. It should be noted that, to date, TransAlta's SIR has operated with a minimum threshold for claims ($100,000) and there has been no self insurance coverage for generation outages. This is inconsistent with how AE's reserve has been administered. ENMAX considers the past approach for TransAlta to be more reasonable and should be a model for setting reserve policies.

Position of TransAlta

TransAlta submitted that as a result of the structural change in the industry, particularly as it relates to Generation, it is prudent to ensure that there is no material balance in the reserve at the end of 2000 as there is no ready way of dealing with any excess or shortfall in the reserve at 31 December 2000. More particularly, were there to be a positive balance in the reserve at 31 December 2000 (i.e. contributions to the reserve exceeding claims) there currently exists no mechanism to return those excess funds to customers at that time. Similarly, should the reserve be in a negative position (i.e. claims exceeding contributions) there is no defined mechanism for TransAlta to recover such a shortfall from customers post 31 December 2000. Accordingly TransAlta submitted that its approach is entirely reasonable considering the structural changes expected to occur in the industry and requested Board approval of its proposal.

[382] Tr. p.3877
[383] Tr. p.3878
[384] Tr. p.3884-3895
[385] Tr. p.3890

Board Findings

To date, all three Utilities have had self-insurance reserves which were considered to be the most beneficial approach. The Board is not persuaded that it would be beneficial to customers to eliminate the self-insurance reserve in favor of commercial insurance for the 1999-2000 period. The Board notes the comments of ENMAX that the risk reduction that results from commercial insurance comes at a high price for 1999 and 2000. The Board agrees with the comments of the FIRM Customers that based on the average claim experience over the last three years of $1.2 million, the self-insurance reserve balance of $4.8 million at 31 December 1998, has about 4 years of "life" left. Based on a balance of probabilities, it does not appear likely the reserve amount as at 31 December 1998, will be depleted by 31 December 2000.

The Board agrees with the Intervenors that the TSR is the appropriate vehicle to deal with relief from UOV payments during 1999 and 2000. The Board also agrees with the FIRM Customers that the additional insurance for third party liability for a hydro breach has not been necessary in the past and TransAlta provided little evidence for its sudden need in 1999 and 2000.

Accordingly, for all of the above reasons the Board denies TransAlta's request to eliminate the self-insurance reserve for 1999 and 2000. The Board notes that the proposed additional commercial insurance costs were categorized as follows:

- Replacement of the self-insurance reserve at a cost of $2 million per year,
- Additional insurance for generation forced outages at a cost of over $1 million per year,
- New insurance for third party liability for a breach at one of the hydro dams at a cost of $1.5 million per year, and
- Other unidentified amounts of $1.5 million.

The Board directs TransAlta, in its refiling, to remove the additional commercial insurance premiums of $6.1 million[386] and reinstate the self-insurance reserve. The Board considers that it is not necessary to provide any additional funding to the self-insurance reserve for the 1999 and 2000 test years as the balance of $4.8 million as at 1 January 1999 can be used to offset any claims.

The Board, in the section of this Decision dealing with AE's Reserve for Injuries and Damages, determined the Reserve should not be charged with UOV payments for any events subsequent to 1 January 1999. Applications for relief of UOV payments shall be made via the TSR mechanism. This same direction and approach to filing a TSR would apply to TransAlta. Therefore, the Board directs TransAlta, if it wishes to claim for UOV payments, to use the TSR mechanism rather than the self-insurance reserve. TransAlta has the opportunity to make a TSR Application to cover such losses.

[386] Tr. p.3879

The Board directs TransAlta, in any application for a TSR, to include adjustments, similar in methodology, as the Board directed AE to include in the section of this Decision dealing with AE's Reserve for Injuries and Damages.

The Board directs TransAlta to apply to the Board for final disposal of the closing balance of the self-insurance reserve as at 31 December 2000. At the time of the application, the Board will review the charges to the self-insurance reserve and approve the disposition of any remaining balances to the Balancing Pool.

(j) Depreciation

TransAlta did not complete a full depreciation study for the 1999/2000 Application, but reviewed (and updated where necessary) the study performed for TransAlta's 1996 application. The review revealed no general requirement to vary the depreciation parameters and rates approved in Board Decision U97065. TransAlta considered that by maintaining the parameters and rates approved in Decision U97065, TransAlta had fully complied with Part 5 of the GUR established under Ministerial Order 12/99 signed 15 March 1999.

Position of TransAlta

Annual Provision

Application of the depreciation rates to TransAlta's forecast property balances, additions, and retirements for 1999 and 2000 resulted in the forecast depreciation expense of $241.0 million and $249.6 million respectively, as set out in Schedules 7.3.4 and 7.3.5 as revised 14 April 1999 in Exhibit 60. These amounts compare to a current estimate of $235.9 million for 1998 (excluding the adjustment to 1995 depreciation resulting from Board Order U98124 booked in 1998). To the extent that actual recorded opening balances for 1999, or forecast additions or retirements for 1999 and 2000, change in any subsequent refiling, the requested depreciation provision would proportionately change.

The one exception to TransAlta's continuation of the depreciation rates and parameters approved in Decision U97065 is in respect of the retirement of the High River Service Centre in 2000. The requested depreciation provision includes an amortization of reserve deficiency resulting from that retirement, in the amount of $0.5 million per year for 1999 and 2000. The requested provision also includes amounts for continued amortization of reserve deficiency as approved in Decision U97065.

Accumulated Depreciation

TransAlta submitted that the amounts of accumulated depreciation at year-end to be used in determining its rate base for 1999 and 2000 are $3,120.5 million and $3,326.1 million respectively. These are the amounts set out in Schedules 7.2.4 and 7.2.5 as revised 14 April 1999

in Exhibit 60, less the $6.4 million adjustment to 1995 depreciation resulting from Board Order U98124 and set out in Exhibit 117. These amounts would also be subject to change resulting from use of actual recorded opening balances for 1999 or changes in forecast additions or retirements for 1999 and 2000, in any subsequent refiling.

The 1999 and 2000 year-end accumulated depreciation includes the 1999 and 2000 provisions for depreciation calculated in accordance with the proposed rates set forth in Schedules 7.3.4 and 7.3.5 as revised 14 April 1999 in Exhibit 60.

Position of ENMAX

ENMAX noted that it wanted to gain assurance that only a proper and fair level of depreciation was incorporated in TransAlta's revenue requirement. Further, ENMAX also sought to understand the nature and extent of TransAlta's compliance with the GUR. ENMAX considered that TransAlta had endeavored to comply with the GUR in a manner to which ENMAX did not object.

ENMAX noted that there were a number of corrections of original errors that were discussed on the record and in the final exhibits of this proceeding. ENMAX stated that it was concerned with the manner in which the 1999 corrections were introduced into the hearing record. It is the view of ENMAX that the corrections should have been made at the time the errors were found, or at least prior to the commencement of these hearings. Rather, both the revision of evidence to comply with the GUR and the correction of significant inconsistencies in the depreciation schedules were not made until 14 April 1999,[387] one month after the issuance of the GUR and following a series of information requests from ENMAX.

ENMAX reviewed the initial TransAlta evidence and identified that the following four parameters had been changed since the approval of TransAlta's depreciation component of revenue requirement in the Board's Decision U97065:

- Modifications to the Monenco net salvage study filed in 1996, to incorporate complete removal of penstocks and the removal and regarding of dikes at several hydro locations.
- Updating of the salvage proceeds and cost of retiring TransAlta's thermal generating units and the related coal mining property.
- Revised retirement dates for the generating units on the Bow River as a result of TransAlta's PPA negotiations.
- A request to amortize the accumulated depreciation variance over the estimated remaining lives of the plants.

[387] Exhibit 60

With the exception of the depreciation rate impacts arising from the retirement of the High River Warehouse, all of the above modifications were removed in the evidence re-filed by TransAlta on 14 April 1999.[388]

The evidence filed on 14 April 1999 did not distinguish the changes that were made as a result of the compliance to the GUR from the changes that were made as a result of corrections of errors. Furthermore, the errors were not identified and corrections were made with no explanation. Although the GUR should only have resulted in modifications to four accounts in the year 1999, every TransAlta plant account was modified, and in the year 2000, all but one account was modified. The lack of detail in both the initial evidence and the re-filed evidence resulted in a significant amount of cross-examination time in order for ENMAX to understand the evidence. The evidence was obviously confusing to the TransAlta witnesses as well. TransAlta provided nine undertakings in approximately one hour of cross-examination on the depreciation evidence. Unfortunately, the undertaking responses filed as Exhibit 81 were equally unclear and resulted in over two more hours of cross examination and three additional undertakings. Only in the undertaking response entered as Exhibit 120, did ENMAX receive sufficient detail to resolve many of the basic questions surrounding the depreciation calculations.

ENMAX submitted that the bases for the calculations and depreciation rates used by TransAlta in their depreciation evidence can be understood as a consequence of ENMAX's cross-examination. TransAlta made the following depreciation related corrections to the evidence filed on 30 October 1998:

- Correction of the depreciation rates used in the calculation of the 1998 depreciation provision. TransAlta entered Exhibit 117 to identify the magnitude of this error.
- A retirement of $8.1 million of coal rights for both 1999 and 2000 was missed in the original application in error, but corrected on the revised depreciation schedules filed on 14 April 1999. As these retirements are amortized to operating cost[389] rather than retired through the accumulated depreciation account, the rate base for both 1999 and 2000 is overstated by $8.1 million in each year. As such, the return on rate base component of the revenue requirement must be adjusted to reflect this reduction in rate base. This change to the return on rate base calculation was not made in the revised material. If this adjustment is not made, TransAlta would not only be recovering the $8.1 million per year through the operating cost, as it was included in operating cost in the original application,[390] but also would earn a return on it as it has not yet been removed from rate base.
- The corrections and revisions resulting from the GUR, entered by TransAlta on 14 April 1999,[391] could not be isolated and individual impacts determined by either ENMAX or the TransAlta witnesses during cross-examination. In aggregate, TransAlta has indicated that the

[388] Exhibit 60
[389] Exhibit 81
[390] Exhibit 81
[391] Exhibit 60

1999 depreciation expense should be reduced by $1.3 million (Schedule 7.3.4 filed on October 30,1998 showed $242.3 million versus the $241.0 million indicated on page 1 of Exhibit 120) and the 2000 depreciation expense should be reduced by $6.2 million ($255.8 million indicated on Schedule 7.3.5 filed 30 October 1998 versus the $249.6 million indicated on page 2 of Exhibit 120). However, these depreciation expense reductions have not yet been reflected in the 1999 and 2000 revenue requirements.

ENMAX recommended that TransAlta reflect the above corrections in its revenue requirements.

Board Findings

The Board notes, with approval, that TransAlta revised the depreciation portion of its filing to comply with the requirements of the GUR. The Board also notes that the one exception to TransAlta's continuation of all of the depreciation rates and parameters approved in Decision U97065 is in respect of the High River Service Centre in 2000.

TransAlta requested an increase to the amortization of the reserve deficiency for Buildings-General to reflect the proposed retirement of the High River Service Centre. The Board notes that TransAlta's proposal to amortize any account reserve deficiency (which exceeds a 5% tolerance limit) over the remaining life of the account is consistent with past depreciation practice approved by the Board.

For all of the above reasons, the Board approves TransAlta's depreciation parameters and rates except as noted in the following Board direction.

The Board directs TransAlta, in its refiling, to recalculate the annual depreciation provision and accumulated depreciation for each of GENCO, TRANSCO and DISCO incorporating the following:

- The depreciation related errors and corrections identified by TransAlta.
- The forecast net proceeds for the High River Service Centre approved by the Board in the Corporate Capital Additions Part 4–TAU, Section 1(b)(3) of this Decision.
- The actual recorded opening plant balances as of 1 January 1999.
- The forecast capital additions for 1999 and 2000 approved by the Board in this Decision.
- Changes made to coal amortization as determined in Part 4–TAU, Section 2(c)(1) of this Decision.

The Board generally agrees with the comments of ENMAX that an Applicant should file any corrections to its application together with full explanations prior to the commencement of the proceeding. The Board considers that such a procedure improves the efficiency of the proceeding and expects TransAlta to follow this procedure in future GTAs.

2. GENCO

(a) Rate Base

(1) Capital Additions

In its Application TransAlta requested approval for Generation capital additions in the amount of $97.0 million for 1999 and $78.0 million for 2000 (see Table below).

2. GENCO
(a) Rate Base

TransAlta Generation Capital Additions ($Millions)		
	1999	2000
Highvale Ash Hauler Replacement	5.3	0.0
Highvale Coal Hauler Replacement	16.9	0.0
Highvale Pit 2 Drainage Ditch	1.2	0.0
Sundance 1-4 Secondary Crusher Upgrade	1.5	0.0
Brazeau 2 Generator Stator Rewind	3.0	0.0
Wabamun 4 Pulverizer Refurbishment [392]	1.0	0.8
Sundance Plant Feedwater Plant[393]	11.5	0.4
Sundance 1 #7 Feedwater Heater Replacement	1.3	0.0
Sundance 1 #5 and #6 Feedwater Heater Replacement	2.7	0.0
Keephills 1 #6 Heater Replacement	1.4	0.0
Sheerness Capital	3.1	4.4
Highvale Mine Shop	0.0	13.9
Highvale Pit 2 County Landfill Move	0.0	1.0
Highvale Freehold Royalty Deferral[394]	0.8	2.0
Spray Woodstave Pipeline Replacement	0.0	2.0
HMS Maintenance Shop	0.0	1.7
Bighorn Compensating Water Facilities	0.0	8.0
Wabamun Boiler Asbestos Removal	0.0	1.0
Wabamun 4 Waterwall Replacement	0.0	1.2
Sundance Gen Spare LP Rotor Purchase	0.0	1.5
Sundance 2 #5 & #6 Feedwater Heater Replacement	0.0	0.0
Sundance 2 Boiler Control Replacement	0.0	1.0
Sundance 3 Boiler Control Replacement	0.0	1.1
Sundance 4 #5 & #6 Feedwater Heater Replacement	0.0	0.0
Keephills-Raise Primary and Secondary Ash Lagoon Dykes	0.0	2.5
Projects < $1,000,000	47.3	35.5
Total	97.0	78.0

The issues that arose during the proceeding pertaining to individual projects included in the Generation Capital Additions are addressed below.[395]

[392] The Wabamun 4 Pulverizer Refurbishment project did not appear in the year 2000 Generation CWIP Continuity schedule (TransAlta Application, Section 2.4.) Accordingly, the $800,000 included in the project authorization for expenditures has been added in year 2000 of this table.

[393] The Sundance Water Treatment Plant should have included a proposed expenditure of $350,000 in the year 2000 to agree with the authorization for expenditures for this project.

[394] The Highvale Freehold Royalty Deferral project should have shown $800,000 assigned to 1999 to agree with ENMAX.TransAlta-46(g)(iv) and Exhibit 75.

[395] TransAlta Application, Section 2.4

(A) Capital Project Justification

Position of the FIRM Customers

The FIRM Customers noted that the economic analysis perform by TransAlta for various capital projects tended to differ in approach and consistency and was, in many cases, inadequate to make rational decisions. Project evaluation should look at the operating cost savings compared to the rate base (capital) related expenses. The resulting cash flow should have a positive net present value for the project to be economically attractive to customers.

The FIRM Customers stated that, for the economic justifications provided for the Ash and Coal Haulers, this approach was used. However, in the economic justification for the Sundance 1-4 Secondary Crusher Upgrade and other projects, a different approach was utilized. TransAlta used a simple cash flow model comparing the $1.5 million capital expense of the upgrade vs. annual estimated operating cost savings. The FIRM Customers stated that this approach would be appropriate for a business but not a utility. If TransAlta plans to capitalize these expenditures, rather than expense them, then the analysis provided was not adequate.

The FIRM Customers also submitted that the level of detail provided to justify capital expenditures of many millions of dollars was totally inadequate. During the last Phase I hearing there was considerable debate over the need for some of the capital projects and the Utilities' lack of justification. In response, the Board ordered: "[the] Utilities, to be more forthcoming with respect to the depth of the analyses they used to justify the prudence of their decisions." The FIRM Customers recommended that the Board consider the level of detail provided and the inconsistent methodologies used by TransAlta in justifying their proposed capital expenditures.[396]

Board Findings

The Board agrees that the correct approach to project economic analysis for utilities should be undertaken from the point of view of the customers and further, should contain sufficient detail for interested parties to test the underlying assumptions of the analysis.

The Board considers that TransAlta has made considerable improvement towards the requirement of providing sufficient background and economic analysis to substantiate the prudence of capital addition projects. The Board considers it important to standardize on the method of economic analysis including the use of a single, consistent and appropriate discount rate. The Board agrees with the FIRM Customers that the economic analysis provided for the ash haulers[397] is illustrative of the approach expected and is considered by the Board to be appropriate.

[396] FIRM Customers Argument, p.163-164
[397] Exhibit 116

However, the Board considers that the economic analysis should clearly set out the assumptions used respecting discount rate, operating expense, depreciation, income tax and return. Using the ash hauler economic analysis as an example, the Board considers that the assumptions and working papers respecting the derivation of operating expenses using the existing fleet and the operating expenses using the new ash haulers should have been included in the analysis.

(B) Highvale Ash Hauler Replacement

Position of TransAlta

TransAlta proposed to replace the existing ash hauler fleet at the Highvale Mine with two new bottom dump ash haulers. The total capital cost in 1999 would be $5,256,540 with an anticipated annual operating cost reduction of approximately $700,000. The projected net present value of savings of this option was $2.7 million compared with maintaining the existing fleet.

TransAlta noted that the existing ash hauler fleet has, on average, 48,000 operating hours. Mechanical availability is approximately 76% and parts and service components are becoming increasingly difficult to obtain. In this situation, ash disposal at the Sundance Generating Station may be at risk.[398]

In argument, TransAlta noted that operating savings to customers would be $1.6 million over the test years. The existing ash haulers have reached or exceeded the industry average standard life for replacement. On this basis, TransAlta submitted that the purchase of the ash haulers was reasonable.[399]

TransAlta countered the FIRM Customers' argument that they had not addressed other alternatives to replacing the ash hauler fleet or deferring those purchases over a period of time. Mr. Clark addressed the reasons for replacing the ash haulers during cross-examination. He noted the following reasons:

- The existing fleet of trucks is at the end of its useful life;
- Replacing the fleet gradually would require two sets of parts inventories;
- Running different types of trucks would create problems with queuing and how the fleet works together because they travel at different speeds.

TransAlta submitted that there was ample evidence on the record confirming that they had considered alternatives to replacing the ash haulers, but ultimately found the customers received the most benefit from a complete replacement of the fleet.[400]

---

[398] TransAlta Application, Section 2.4
[399] TransAlta Argument, p.15
[400] TransAlta Reply Argument, p.7

Position of the FIRM Customers

Acquisition of the ash haulers was justified by TransAlta based on a net present value analysis. This analysis considered only two alternatives, retention of the old fleet and acquisition of an entirely new fleet. It did not address other alternatives to defer or stage these purchases over a period of time.

The FIRM Customers noted that, as stated by Mr. Clark, the ash haulers "have not been ordered yet" and design of the ash handling system was not complete (as of 26 April 1999). TransAlta had not received confirmation from the supplier as to an actual delivery date for the ash haulers at that time. Notwithstanding this uncertainty, TransAlta proposed to include the cost of the ash haulers in its 1999 rate base.

TransAlta claimed that the new fleet of ash haulers would reduce annual operating costs by approximately $700,000. However, the evidence indicated that the average savings in operating cost, less the capital related cost, for the first five years is only $17,000 per year. It is only after 2004, when the forecast operating costs for the new ash haulers would drop for two years, that the replacement of the old units begins to make economic sense. The TransAlta analysis was subject to a significant degree of sensitivity. Any error in TransAlta's forecasts could be greater than the marginal benefit of the project. This appeared to put this project in the "want" rather than "need" category.

The FIRM Customers submitted that this appeared to be a case of TransAlta requesting customers to pay for new equipment on the eve of generation deregulation. With high capital cost forecasts going into the PPAs, customers would not have the opportunity to determine if the proposed investment is in their interest.

The FIRM Customers submitted that the proposed capital cost for the new ash haulers should not be added to rate base in 1999; and the Board should consider the validity of TransAlta's economic analysis in determining if this capital expenditure is warranted for inclusion in rate base in 2000.[401]

Board Findings

The Board notes that, in argument, the FIRM Customers have agreed that the economic evaluation of this project was correctly calculated. This is separate from the question as to whether or not appropriate alternatives were considered. However, at the least, it can be stated that allowing this project as applied for would have a positive net present value for customers into the future compared with maintaining the existing fleet of ash haulers.

The Board recognizes that questions of operability and reliability are also valid criteria for capital expenditures. The Board accepts the evidence of TransAlta that the best solution is to replace the entire ash hauling fleet at this time.

[401] FIRM Customers Argument, p. 164-168

However, given that these major capital items had not been ordered as of the end of April 1999, the Board finds it unlikely that they will enter useful service during this year. Therefore, the Board directs TransAlta, in its refiling, to remove the Highvale Ash Hauler project from the year 1999 rate base and include this expenditure in the year 2000 rate base.

(C) Highvale Coal Hauler Replacement

Position of TransAlta

TransAlta proposed to replace the existing coal hauler fleet at the Highvale mine with nine new 160-ton coal haulers at a capital cost of $16.9 million in 1999. The existing 13 units have on average 55,000 to 72,000 operating hours. The typical lifetime of these units is 50,000 to 60,000 hours. Mechanical availability has been approximately 65% and parts and service components have been becoming obsolete and more difficult to obtain.

The anticipated annual operating cost reduction with the new fleet is approximately $3 million with net present value of savings of $2.7 million versus maintaining the existing fleet.[402]

The projected operating savings to customers were approximately $8,000,000 over the test period. TransAlta submitted that the cost savings associated with the replacement of the coal haulers had been amply demonstrated through exhibits, information requests, and the extensive testimony of Mr. Clark.[403]

TransAlta countered the FIRM Customers' argument that they had not addressed other alternatives to replacing the coal hauler fleet or deferring those purchases over a period of time. Mr. Clark addressed the reasons for replacing the coal haulers during cross-examination. He noted the following reasons:

- The existing fleet of trucks is at the end of its useful life;
- Replacing the fleet gradually would require two sets of parts inventories;
- Running different types of trucks would create problems with queuing and how the fleet works together because they travel at different speeds.

TransAlta submitted that there was ample evidence on the record confirming that they had considered alternatives to replacing the coal haulers, but ultimately found the customers received the most benefit from a complete replacement of the fleet.[404]

---

[402] TransAlta Application, Section 2.4
[403] TransAlta Argument, p.15
[404] TransAlta Reply Argument, p.7

Position of the FIRM Customers

Acquisition of the coal haulers was justified by TransAlta based on a net present value analysis. This analysis considered only two alternatives, retention of the old fleet and acquisition of an entirely new fleet. It did not address other alternatives to defer or stage these purchases over a period of time.

The new coal haulers were forecast to be in place and working by the end of May, 1999. TransAlta claimed operating cost savings would average $3 million per year.

TransAlta has operated a mixed fleet of coal hauling trucks for over 12 years. The existing fleet was purchased over a six-year period from 1980 to 1986. There appeared to be no sound reason why the existing trucks could not be phased out over a period of several years. TransAlta claimed that having two different types of trucks would increase the cost of carrying two types of parts inventories. However, TransAlta has been using two different types of coal hauling trucks at Highvale for years. TransAlta did not satisfy the test that all these new trucks are required in 1999. While it would be nice to have all new equipment going into an era of uncertainty, the existing trucks are not that old and are not being replaced with larger units.

The FIRM Customers recommended that the forecast $16.92 million capital cost for the new coal haulers be phased in over five years. A total of $3.38 million should be added to rate base in each of 1999 and 2000, with the remainder held as PHFFU/AFUDC for inclusion post 2000, assuming TransAlta has purchased the new equipment.

The FIRM Customers were concerned with the apparent sense of urgency in replacing TransAlta's entire ash and coal handling fleet. They questioned the effect the PPA process may have had on these decisions.[405]

Board Findings

The Board notes that, as with the Highvale Ash Hauling fleet replacement project, the FIRM Customers have agreed that the economic evaluation of this project was calculated correctly. This is separate from the question as to whether or not appropriate alternatives were considered. However, at the least, it can be stated that allowing this project as applied for would have a positive net present value for customers into the future compared with maintaining the existing fleet of coal haulers.

The Board recognizes that questions of operability and reliability are also valid criteria for capital expenditures. The Board accepts the evidence of TransAlta that the best solution is to replace the entire coal hauling fleet at this time. The Board notes the evidence that these trucks are already arriving at site and therefore approves the inclusion of this project in rate base for TransAlta in 1999.

[405] FIRM Customers Argument, p.164-168

(D) Highvale Pit 2 Drainage Ditch

Position of TransAlta

The ongoing advancement of Pit 02N at the Highvale Mine required the relocation of the Primary Drainage Ditch. The purpose of this ditch was to allow the diversion of clean surface water away from the active mining area, ensuring a safe and stable operation. Total capital cost for this project was estimated to be $1.2 million in 1999.[406]

TransAlta noted the FIRM Customers and ENMAX argued that because there had been no tender for this project as of 26 April 1999 the project should be not be included in rate base until year 2000. TransAlta stated the topsoil stripping was planned for the third quarter of 1999, rendering the existing ditch ineffective in conveying clean surface run-off from around the active mining area to Wabamun Lake. As TransAlta was familiar with this type of drainage ditch, they submitted that it is not unusual for this project not to have been tendered by April 1999.[407]

Position of the FIRM Customers

The FIRM Customers noted that although TransAlta proposed to mine these future areas in 1999, no contract had been tendered for the ditch project as of April 26, 1999.[408]

Board Findings

The Board finds this project to be necessary. The Board accepts the statements of TransAlta that the project is expected to be undertaken in 1999 notwithstanding that the project had not been tendered as of the end of April 1999. Therefore, the Board allows this project to be included in the 1999 rate base for TransAlta.

(E) Sundance 1-4 Secondary Crusher Upgrade

Position of TransAlta

Coal handling systems for Sundance 1/2 and 3/4 have been in operation since 1969 and 1973 respectively. TransAlta noted there was no redundancy incorporated for Sundance 1/2 operations with respect to the secondary crushing system. The secondary crushing systems for both plants were very maintenance and labor intensive due to their age and design. Operating the secondary crushing circuits with 2 double roll heavy-duty crushers and crossover chutes would eliminate the risk to coal supply for Sundance 1/2 and reduce annual operating costs by $426,000. The cost savings were due to reduced manpower, reduced power consumption, lower maintenance costs, and increased generation (resulting from reduced de-rates due to feeder trips).

[406] TransAlta Application, Section 2.4
[407] TransAlta Reply Argument, p.7
[408] FIRM Customers Argument, p.168

Capital investment for the upgrade is $1,500,000 resulting in a net present value of savings of $1,420,000.[409]

Position of the FIRM Customers

The FIRM Customers noted that, although Mr. Clark had stated that this project was to be completed before the end of 1999, the project had not yet been tendered as of 26 April 1999. The only identified consequence was "the savings would be pushed on further into the future."[410]

Position of ENMAX

TransAlta has justified a number of projects on the basis of improved generating performance. TransAlta testified that these additions are not expected to increase the generating performance of the units but only bring generation units back to "design", with the result being they would hold the five year average FMOR. The evidence showed that TransAlta has generally been successful at improving on its five year average FMOR without capital expenditures for generation performance. ENMAX argued that if customers are expected to pay for these improvements they should receive credit for the improved performance.[411]

Board Findings

The Board notes that, although the calculation of the net present value of savings attributable to this project is under dispute by the FIRM Customers, the magnitude of those savings makes it unlikely that the economic decision would be reversed by the changes suggested to the calculation method.

However, the Board is concerned that this project will not be operational in 1999, as applied for. Further, the Board accepts TransAlta's evidence that this project is required to maintain generating performance and will not increase the historical generating performance of the Sundance 1-4 units. However, the Board notes that generating performance has been increasing over the last few years without significant capital expenditures. The Board, in the GENCO deferral account section found that it was important to set the generating performance standard at a reasonable and demonstrably achievable level. The Board directed, for the purposes of the refiling, that all forecast modeling parameters be determined using actual performance data over the three-year period 1996-1998. The Board is satisfied that, with the above method of determining performance standards, it would be appropriate to accept projects of this nature that are required to maintain recent generating performance.

Accordingly, for all of the above reasons, the Board approves this project for inclusion in rate base for TransAlta in 2000. The Board directs TransAlta, in its refiling, to remove the Sundance

[409] TransAlta Application, Section 2.4
[410] FIRM Customers Argument, p.169
[411] ENMAX Argument, p.28

1-4 Secondary Crusher project from the year 1999 rate base and include it in the year 2000 rate base.

(F) Brazeau 2 Generator Stator Rewind

Position of TransAlta

Tests on Brazeau 2 had indicated an increase in the degradation of the unit's stator coils. A recent failure of one of these coils had confirmed the condition of the stator and the removal of this coil had increased the risk of future coils failures. Stator coil failures result in costly generation losses and extended forced outages. Depending on the timing, these forced outages can also have serious environmental implications associated with spilling water from the reservoir. It was recommended that the stator coils be replaced to mitigate the risk of failure. Capital cost for this project was estimated to be $3 million.[412]

Board Findings

The Board finds that the failure of one of the coils in the stator is clear evidence of the need for replacement of these pieces of equipment. The Board approves the inclusion of this project in rate base for TransAlta in 1999.

(G) Wabamun 4 Mill Refurbishment

Position of TransAlta

Major refurbishment of the Wabamun 4 mills would provide a significant improvement to mill performance. Total capital costs for this project were estimated to be $1 million in 1999 and $800,000 in 2000. Net present value of savings for this project were $248,000.[413]

The capital investments proposed for the Wabamun plant were required to maintain historical generation capability over the remaining years of regulated life. TransAlta argued that without these capital additions, there would be a severe degradation in equipment performance and generating capability.[414]

Position of the FIRM Customers

The FIRM Customers noted that, as well as the expenditures proposed for the Wabamun plant during the test period, significant expenditures had been undertaken on this plant in recent years. These included expenditures of $3.2 million in 1996, $5.1 million in 1997, and $4.8 million in 1998. The FIRM Customers submitted that it was questionable as to whether this level of

[412] TransAlta Application, Section 2.4
[413] TransAlta Application, Section 2.4
[414] TransAlta Reply Argument, p.33

expenditure was warranted on a plant which TransAlta proposed to retire three years following the test period.[415]

Mr. Benedict had indicated that the mills had not been replaced for 20 or 30 years and was part of a longer plant program. It must be questioned why these expenditures are being incurred just three years before the end of the base plant life.[416]

Position of ENMAX

ENMAX noted that TransAlta justified a number of projects on the basis of improved generating performance. TransAlta testified that these additions are not expected to increase the generating performance of the units but only bring generation units back to "design", with the result being they would hold the five year average FMOR. The evidence showed that TransAlta has generally been successful at improving on its five year average FMOR without capital expenditures for generation performance. ENMAX argued that if purchasers are expected to pay for these improvements they should receive credit for the improved performance.[417]

Board Findings

The issue of adding significant capital additions to a plant that is near regulated retirement is complicated in this case by the intervention of the PPA process. As the questions of the future residual value of plant capital and the treatment of plant capital in the PPA process is outside of the scope required of this decision, the Board will determine the validity of this project based on its effect on customers during the test period and over the remaining years of regulated life.

The evidence before the Board is that this project will be of value to customers during the test period and beyond. Therefore, the Board approves the addition of this project to rate base for TransAlta in 1999 and 2000 as per its application. The Board has provided additional reasons for accepting projects of this nature and their effect on generating performance in the section dealing with the Sundance 1-4 Secondary Crusher Upgrade project above.

(H) Sundance Water Treatment Plant Replacement

Position of TransAlta

The existing Sundance Water Treatment Plants were characterized as high cost processing plants which do not have the capability to produce the high-quality water that is required for steam production. This leads to excessive corrosion resulting in forced derates and outages on all generating units. The existing plants required a significant injection of capital to allow them to operate for the remaining life of the Sundance Generating Plant. GBS Production Engineering recommended a new water treatment plant be designed to replace the existing #3 and #6 plants.

[415] FIRM Customers Argument, p.163-164
[416] FIRM Customers Argument, p.169
[417] ENMAX Argument, p.28

Total capital cost of this project was estimated to be $11,880,000 with expected net present value of savings of $4,420,188.[418]

Boiler water chemistry at Sundance has been below industry standards. An independent consultant has identified water chemistry as an area for improvement. Addition of the water treatment facility was expected to reduce outages due to corrosion.[419]

TransAlta noted that the Sundance Water Treatment Plant was expected to be completed by the end of 1999.[420]

Position of the FIRM Customers

The business case evaluation for this project showed revenues, operating expenses, and taxes commencing in the year 2000 whereas it is treated as a 1999 project for revenue requirement purposes. Mr. Benedict indicated he believed this project would be finished at the end of 1999. The FIRM Customers submitted that with this amount of uncertainty, there is a distinct possibility the in-service date could be deferred until 2000.[421]

Board Findings

The Board finds that the expected net present value of savings associated with this project will be in the interest of customers. The Board does note that this project is included in the overall criticism that the FIRM Customers have raised with regards to the calculation of economic benefits. However, in this instance the Board is of the opinion that the change in calculation method would not affect the resulting decision.

The Board shares the concern that the project will not be completed in 1999. The Board also notes TransAlta is uncertain that the project will be completed by the end of 1999. In view of the uncertainty, the Board directs TransAlta, in its refiling, to remove the Sundance Water Treatment Plant project from the year 1999 rate base and include it in the year 2000 rate base.

(I) Feedwater Heater Replacements

Position of TransAlta

The Sundance 1 feedwater heater #7, Sundance 1 feedwater heaters #5 and #6, and Keephills 1 feedwater heater #6 have been experiencing poor reliability and were responsible for increased maintenance costs, increased coal consumption, and de-rates. These heaters have reached the end of their useful lives. GBS Production Engineering recommended replacing the Sundance 1 feedwater heaters #5 and #6 in 1999. By replacing the heaters in 1999, TransAlta could avoid an

[418] TransAlta Application, Section 2.4
[419] TransAlta Argument, p.14
[420] TransAlta Reply Argument, p.4
[421] FIRM Customers Argument, p.169

accelerated growth in de-rates, maintenance costs, and heat rate losses. Project capital costs and projected net present value of savings are shown below.[422]

TransAlta Feedwater Heater Replacements		
Unit	**Capital Cost**	**Net Present Value of Savings**
Sundance 1 #7	$1,340,000	$1,583,457
Sundance 1 #5 & #6	$2,700,000	$2,672,949
Keephills 1 #6	$1,400,000	$1,866,708

TransAlta countered the FIRM Customers' argument that the timing of the proposal to replace eight high-pressure feedwater heaters at the Sundance and Keephills plants was driven by the PPA process and was otherwise not urgent. The feedwater heaters have been experiencing poor reliability resulting in increased maintenance costs, increased coal consumption, and increased unit derates. Mr. Benedict indicated that, "if we leave the heaters in the condition they are in, there will be a safety concern, plus there will be a degradation of megawatt output." TransAlta submitted that the need to complete these capital projects has been demonstrated.[423]

Four other feedwater heater replacements were included by TransAlta in its Application: Sundance 2 #5 and #6, and Sundance 4 #5 and #6. These projects were not forecast to enter rate base in 1999/2000.

Position of the FIRM Customers

TransAlta proposed to replace eight high-pressure feedwater heaters at its Sundance and Keephills plants at an average per unit cost of approximately $1.35 million. The FIRM Customers stated that these projects clearly result in a betterment to the system but there did not seem to be urgency in terms of their in-service dates. Not all of the projects have been tendered.

The FIRM Customers submitted that these are projects that could and may well be deferred beyond their currently forecast in-service dates. This spate of feedwater heater replacements may well be driven by the PPA process.[424]

Position of ENMAX

TransAlta has justified a number of projects on the basis of improved generating performance. TransAlta testified that these additions are not expected to increase the generating performance of the units but only bring generation units back to "design," with the result being they would hold the five-year average FMOR. The evidence showed that TransAlta has generally been successful at improving on its five-year average FMOR without capital expenditures for

[422] TransAlta Application, Section 2.4
[423] TransAlta Reply Argument, p.35
[424] FIRM Customers Argument, p.170

generation performance. ENMAX argued that if purchasers are expected to pay for these improvements they should receive credit for the improved performance.[425]

Board Findings

The Board notes that these projects demonstrate a substantial net present value of savings to customers. Because of this, it is logical to proceed with these projects earlier rather than later. The Board notes that only four of the eight heater replacements are scheduled for the test years. The four feedwater heater projects scheduled for completion after the year 2000 are outside the scope of this proceeding.

Therefore, the Board accepts the inclusion of these projects into rate base for TransAlta in 1999. The Board has provided additional reasons for accepting projects of this nature and their effect on generating performance in the section dealing with the Sundance 1-4 Secondary Crusher Upgrade project above.

(J) Sheerness Capital

Position of TransAlta

The Sheerness Generating Station is 50% owned by TransAlta Utilities. AE owns the other 50% and acts as the operating owner. This project covers TransAlta's 50% share of the capital expense for the Sheerness Plant in 1999 and 2000. Total capital cost for this project was $7,443,113. Costs in 1999 were $3,064,613. Costs in 2000 were $4,378,500.[426]

Board Findings

The Sheerness capital expenditures remained outside of the review of the Board during this proceeding as the operator, AE, reached a negotiated settlement with its customers. The Board notes that Intervenors involved in the negotiations did not object to the proposed capital expenditure. The Board after review, considers the addition to rate base is reasonable and accepts this expenditure as filed.

(K) Highvale Mine Shop

Position of TransAlta

Overburden at the Highvale mine is increasing in depth and in 2001 pre-stripping equipment will be required to maintain required coal production levels. To accommodate the additional equipment in the existing Upper Mine Services Building TransAlta submitted that the building must be expanded in 2000, one year in advance of the required equipment. The existing building was constructed in 1982 and has become fully utilized. The physical dimensions of the

[425] ENMAX Argument, p.28
[426] TransAlta Application, Section 2.4

maintenance area would not support the servicing of the large equipment recommended for pre-stripping. TransAlta recommended that the existing Upper Mine Services Building be expanded southward to include additional service bays, warehouse space, dry area, and office space. The cost estimate for the expansion was $13,932,000.[427]

TransAlta argued that it has demonstrated that the new facility is required in connection with first the assembly and then the maintenance of the new large [overburden] hauling trucks. To allow for such assembly, the shop must be in place before delivery of the equipment is taken. Without a building addition, the trucks would have to be assembled outside in mid winter or in a temporary building. Neither of these options was considered to be reasonable or cost-effective.[428]

TransAlta countered the FIRM Customers' argument that "the inclusion of this capital expenditure in 2000 is optimistic at best" and their conclusion that the project should not be included in rate base in 2000. Construction of the Highvale Mine Shop must begin in 2000 in order to accommodate the assembly of the new 240-ton trucks early in 2001. Mr. Clark confirmed that the new trucks will not fit in the existing warehouse space, and that it is common practice in the industry to build a shop first in order to facilitate the assembly of such equipment. The Mine Shop will be required in 2000, and as it will be used and useful in that year, TransAlta submitted that inclusion in rate base is appropriate.[429]

Position of the FIRM Customers

TransAlta forecast that it would require a fleet of pre-stripping equipment in 2001 to remove overburden in excess of the capacity of the existing draglines. The requirement for pre-stripping was thought to have been required almost ten years ago in 1990. At that time a study was undertaken on the potential costs for a mine services building required to assemble and maintain the fleet of pre-stripping equipment.

The evidence was that the pre-stripping equipment would potentially be required in 2001. TransAlta proposed to build a new mine services building in 2000, ahead of the time it was required in 2001. The capital cost estimate for this building was based on the 1990 study inflated to 2000 dollars. No additional work was done to determine if the mine shop could be built in a more cost-effective way.

The inclusion of this capital expenditure in 2000 is optimistic at best. The need for the building starts in 2001. The need for pre-stripping is based on a mine planning study performed in 1998. The pre-stripping equipment has not yet been ordered. It is possible the need for pre-stripping could be delayed again.

[427] TransAlta Application, Section 2.4
[428] TransAlta Argument, p.15-16
[429] TransAlta Reply Argument, p.35

The FIRM Customers submitted that the forecast $13.93 million capital cost of the Upper Mining Services Building should not be added to rate base in 2000. The Board should adjust the Keephills and Sundance PPAs to reflect the need for a new mine services building post 2000 as appropriate.[430]

In reply argument, the FIRM Customers noted that throughout the proceeding TransAlta had claimed that the Highvale Mine Shop capital expenditure was needed for a fleet of pre-stripping equipment. In argument, TransAlta claimed that the maintenance facility was required for the assembly and maintenance of new large coal hauling trucks. This new evidence led the FIRM Customers to further question the appropriateness of this proposed capital expenditure.[431]

Position of ENMAX

TransAlta testified that it required a new mine shop at Highvale in order to assemble new coal pre-stripping equipment which would go into service in 2001. ENMAX submitted that as the shop is not required until 2001, it should not enter rate base until 2001. An item not needed until 2001 should be a matter for the Independent Assessment Team to consider in structuring the PPAs. ENMAX recommended that this item be removed from the forecast rate base in 2000.

Board Findings

The Board shares the concerns expressed by the FIRM Customers that this building expansion may not be used or required to be used during the test period. The Board notes that this mine shop is an integral part of the overall plan for mine overburden removal and will not be used or required to be used until the 240-ton trucks are on-site in 2001.

Therefore, the Board directs TransAlta, in its refiling, to remove the rate base capitalization of the Highvale Mine Shop during the test period and ensure that any expenditures on this project during the test period be held in CWIP pending inclusion in rate base through the PPA process.

(L) Highvale Pit 2 County Landfill Move

Position of TransAlta

Parkland County operated an uncontrolled landfill south of Highvale Pit 2S from 1963 to 1993. In 1994, the southern advance of the mine had reached its safe geotechnical setback from the landfill. Recent geotechnical sloughing and failures in a hillside to the east of the landfill location, the potential for ongoing geotechnical concerns in the area and increasing environmental liability required the landfill to be relocated to the Parkland County's new regional facility.

[430] FIRM Customers Argument, p.170-171
[431] FIRM Customers Reply Argument, p.46

Relocating the landfill would allow flexibility in mine operations and will also remove possible future geotechnical, reclamation, and financial liabilities for TransAlta associated with the open cut adjacent to the landfill. The material will be excavated, sorted and disposed of appropriately. Estimated capital cost is $1,032,000 in 2000.[432]

In reply argument, TransAlta noted that, as stated in IPCAA. TAU-90 (B.), Parkland County does not require the landfill to be moved, but as mining has moved close to the landfill, there are leakage and geotechnical concerns. If TransAlta were not mining in the area, the landfill would not have to be moved by the County. Accordingly, TransAlta submitted that it is not reasonable to expect the County or another party to be responsible for the expense associated with the landfill relocation.[433]

Position of the FIRM Customers

The FIRM Customers argued that based on the evidence provided by Mr. Clark there seemed to be a serious legal question as to the obligation, if any, of TransAlta to pay the cost of relocating the Parkland County landfill site. The question of liability must be addressed and it should not be assumed that the full cost should be borne by TransAlta.[434]

Board Findings

The Board is of the view that the need to move the Parkland County landfill is caused by the presence of mining activities in the area. The Board accepts the evidence that the landfill was located and licensed in accordance with the laws of the day and is still in compliance. Utility customers will benefit from the coal production uncovered by the removal of the landfill and will benefit from the reduction in operations related liability facing TransAlta.

Therefore, the Board accepts the inclusion of this project into rate base for TransAlta in 2000.

(M) Freehold Royalty Deferral

Position of TransAlta

In 1972 and 1982 TransAlta entered into agreements with Fording Coal Limited, Westmin Resources, and PanCanadian for the lease of coal required to supply Sundance and Keephills thermal power plants. The agreements called for each leaseholder to be paid a percentage of the annual production, whether their coal is mined or not, based upon each leaseholder's initial percentage of the coal held in the unitized area. The payments are capitalized, building up in an actual and a deemed stockpile.

[432] TransAlta Application, Section 2.4
[433] TransAlta Reply Argument, p.45
[434] FIRM Customers Argument, p.171-172

As the coal is mined, the coal is drawn from the actual and deemed stockpiles at the weighted average value for that lease, then expensed. The difference between the payments to the leaseholders and the amount expensed each year is the net addition or withdrawal from capital. Year 1999 shows a net addition of $800,000, year 2000 a net addition of $2,008,826.[435]

Board Findings

The Board notes agreements are long standing and approves the capitalization of coal royalties as applied for by TransAlta.

(N) Spray Woodstave Pipeline Replacement

The Spray woodstave pipeline was near the end of its useful life, after 38 years in service. Recent inspections had indicated that continued operation of the pipeline could result in a catastrophic failure. Failure of this penstock would be equivalent to a dam breach and would have grave environmental and economic consequences given the pipeline's location above the Grassi Lakes recreational area and the Town of Canmore. GBS Production Engineering recommended replacement of the woodstave pipeline to mitigate the risk of a catastrophic failure. Estimated capital cost was $2,000,000 in 2000.[436]

Position of ENMAX

ENMAX noted that TransAlta had discovered early in 1999 that the Woodstave project could be avoided by spending $150,000. The forecast for the General Rate Application was filed in October 1998 and TransAlta did not update its capital forecasts, not even to the end of the year. TransAlta did not reduce its forecast additions, not even for projects that are no longer required stating that it expected the monies will be used elsewhere. ENMAX argued that such treatment is inappropriate as it does not provide the Board or Intervenors an opportunity to examine or evaluate the prudence of the projects eventually undertaken.[437]

Board Findings

The Board notes that this project has been cancelled and a $1,850,000 reduction in capital costs has been achieved by TransAlta to accomplish the aims of this project. The Board directs TransAlta, in its refiling, to reduce the proposed Spray Woodstave Pipeline project capital expenditures by $1,850,000 in 2000.

[435] TransAlta Application, Section 2.4 and ENMAX.TAU-46 (g)(iv)
[436] TransAlta Application, Section 2.4
[437] ENMAX Argument, p.29

(O) Hydro Maintenance Services Shop

Position of TransAlta

The existing maintenance facility for the Hydro Maintenance Services group was designed and constructed in 1925 for the Kananaskis and Horseshoe plants. This facility no longer met current Occupational Health and Safety standards. In addition, the existing facilities were required to provide service to 13 hydro facilities. Construction of a new facility was recommended in year 2000 at a capital cost of $1,750,000.[438]

Position of the FIRM Customers

TransAlta's original forecast for 2000 included constructing a new hydro maintenance services facility at a cost of $1.75 million. It was subsequently decided that this project should be deferred and an alternative approved which reduced the cost to approximately $200,000 to $400,000. The rethinking of this budget item may have been an example of how the budget process, as it evolves, results in a more comprehensive analysis and the opportunities for reduced costs.[439]

Position of ENMAX

ENMAX noted that TransAlta had discovered a less expensive alternative to constructing a new hydro maintenance shop. The forecast for the GTA was filed in October 1998 and TransAlta had not updated its capital forecasts. TransAlta did not reduce its forecast additions, not even for projects that are no longer required stating that it expected the monies will be used elsewhere. ENMAX argued that such treatment is inappropriate as it does not provide the Board or Intervenors an opportunity to examine or evaluate the prudence of the projects eventually undertaken.[440]

Board Findings

The Board notes that this project has been cancelled and a $1,450,000 mean reduction in capital costs has been achieved by TransAlta to accomplish the aims of this project. The Board directs TransAlta, in its refiling, to reduce the proposed Hydro Maintenance Services project capital expenditures by $1,450,000 in 2000.

(P) Bighorn Compensating Water Facilities

Position of TransAlta

The Bighorn Plant does not have a bypass system to allow water to flow past the plant and into the river during an extended outage. GBS Production Engineering recommended installation of a gated tunnel penstock bypass system to allow water to flow past the plant and into the river

[438] TransAlta Application, Section 2.4
[439] FIRM Customers Argument, p.172
[440] ENMAX Argument, p.29

during plant outages. This bypass system would mitigate serious environmental consequences and possible legal action against TransAlta in the event of an extended plant outage. Estimated capital cost was $8,000,000 in year 2000.[441]

Due to the configuration of the Bighorn facility, it was expected that flow interruptions exceeding 24 hours would result in both habitat damage and fish kills . It is a violation under the Federal *Fisheries Act* to either: (1) damage or destroy fish habitat; or (2) kill fish by any means other than fishing. A risk analysis of each of the possible scenarios which could result in flow interruptions had identified a significant likelihood of damaging flow interruptions occurring during the remaining life of the facility.[442]

In reply argument, TransAlta noted that the probability of experiencing one or more failures resulting in flow interruptions of greater than 24 hours were estimated to be on the order of 10% in 2000 and 20% in 2001. The failure of the single unit would result in a flow interruption of approximately 18 hours in order to install a bifurcation plate to obtain complete isolation of the failed unit. TransAlta was concerned about the increasing likelihood of flow interruptions given the aging equipment at the plant. TransAlta submitted that ample evidence was provided to show that the construction of the Bighorn Water Compensating Facility was prudent to address environmental concerns.[443]

Position of the FIRM Customers

The FIRM Customers noted that Mr. Benedict had acknowledged that water can be passed through one of the two Bighorn hydro units even if the other is out of service and isolated. Mr. Benedict indicated there had been no instances of damaging interruptions at this facility since it was constructed. Mr. Way indicated that this was one of those areas were TransAlta prided itself on building units cheaply but the time had come to correct the problem. The FIRM Customers questioned whether or not this capital addition was driven by the PPA process.

The FIRM Customers submitted that there was nothing in evidence to suggest or support the need for this addition and it should not be included in the revenue requirement. In addition, there was nothing to suggest that these facilities, as constructed, do not comply with current environmental standards.[444]

Position of ENMAX

ENMAX argued that the Bighorn Water Compensating project is a requested addition without support. The Bighorn dam has been in existence since 1972. The project was said to be required in the event that both Bighorn units are out of service longer than 24 hours. TransAlta had agreed to provide an undertaking to determine if a technical analysis of the probability of stream flow

[441] TransAlta Application, Section 2.4
[442] TransAlta Argument, p.13
[443] TransAlta Reply Argument, p.32
[444] FIRM Customers Argument, p.172-173

interruption at the facility was done. TransAlta had not done any probability analysis of the two units being out at the same time prior to 2000. TransAlta had originally indicated that there had been no incidents of stream flow interruption of more than 24 hours since Bighorn was constructed. Later TransAlta suggested a few incidents had occurred but it did not indicate the severity of the consequences.

Board Findings

The Board notes that TransAlta ultimately provided an estimate of the likelihood of a damaging flow interruption at the Bighorn facility.

Although the facility is currently in compliance with environmental regulations, it is not likely that a new facility would be permitted to be constructed in this fashion. The Board accepts the evidence that TransAlta would be liable under legislation in the event of a prolonged outage. The Board also notes that this facility will remain in service for some time. The probability of a prolonged outage would be a liability throughout the plant's life without mitigation.

The Board finds that is prudent to undertake this project in light of the potential environmental liability existing under current regulation. The Board approves this project for inclusion in rate base for TransAlta in 2000.

(Q) Wabamun Boiler Asbestos Removal

Position of TransAlta

Industry practices during the period when the Wabamun plant was constructed was to insulate temperature-carrying components with asbestos. This material is hazardous if exposed. A program to remove and encapsulate asbestos in the plant was begun about 12 years ago and approximately 50% of the insulation has been removed. Although it was not practical to remove all of the asbestos insulation in the plant, targeted replacement and encapsulation of insulation based on maintenance work scope continued to be an effective means of managing employee exposure to this harmful substance. The cost of this program in 2000, based on the projected maintenance work scope, was $1,000,000.[445]

Position of the FIRM Customers

TransAlta proposed to spend $1.0 million for boiler asbestos removal in the year 2000. The FIRM Customers argued that, given the currently approved base life which expires in 2003, it would seem inappropriate to expend further funds which do not provide any identified benefit and which are dealt with as part of future decommissioning costs.[446]

[445] TransAlta Application, Section 2.4
[446] FIRM Customers Argument, p.173

Board Findings

The Board notes the concerns of the FIRM Customers with this and other projects at the Wabamun plant. However, this issue is clearly one of worker safety and the Board is not of the opinion that it should be deferred. The Board approves the inclusion of this project in rate base for TransAlta in 2000.

(R) Wabamun 4 Waterwall Replacement

Position of TransAlta

Wabamun Unit 4 was a skin cased tangential waterwall tube boiler which was commissioned in 1968, and was the only boiler of this design which TransAlta operated at the time of the proceeding. Boilers of this type have been subject to a number of design problems which affect the operation and condition of the boiler. The Wabamun 4 boiler had seriously deteriorated relative to other boilers in TransAlta's thermal plant. GBS Production Engineering recommended proceeding with the replacement of approximately 400 waterwall tubes in high-risk areas of the boiler in order to address concerns with reliability. Estimated capital cost was $1,200,000 in year 2000.[447]

The capital investments proposed for the Wabamun plant were required to maintain historical generation capability over the remaining years of regulated life. TransAlta argued that without these capital additions, there could be a severe degradation in equipment performance and generating capability.[448]

Position of the FIRM Customers

The FIRM Customers noted that, as well as the expenditures proposed for the Wabamun plant during the test period, significant expenditures had been undertaken on this plant in recent years. These included expenditures of $3.2 million in 1996, $5.1 million in 1997, and $4.8 million in 1998. The FIRM Customers submitted that it was questionable as to whether this level of expenditure was warranted on a plant which TransAlta proposed to retire three years following the test period.[449]

Board Findings

The issue of adding significant capital additions to a plant that is near regulated retirement is complicated by the PPA process. As the questions of the future residual value of plant capital and the treatment of plant capital in the PPA process is outside of the scope required of this decision, the Board will determine the validity of this project based on its effects on customers during the test period and over the remaining years of regulated life.

---

[447] TransAlta Application, Section 2.4
[448] TransAlta Reply Argument, p.33
[449] FIRM Customers Argument, p.163-164

The evidence before the Board is that this project is required to maintain historical generation capability over the remaining years of regulated life. Therefore, the Board approves the addition of this project to TransAlta's rate base in 2000. The Board has provided additional reasons for accepting projects of this nature and their effect on generating performance in the section dealing with the Sundance 1-4 Secondary Crusher Upgrade project above.

(S) Sundance Generation Spare LP Rotor Purchase

Position of TransAlta

This project was a continuation of the low pressure (LP) rotor life achievement program approved in June 1993. As a part of the program, ex-Lakeview LP rotors were leased from Ontario Hydro. The leased rotor provided TransAlta with a rotating spare, so that rotors could be changed out and refurbished without an extended outage. As a result of ongoing inspections, some refurbishments had been deferred until beyond 2000, which would necessitate the need to extend the lease or purchase the rotor outright. Purchase of the rotors represented the lowest cost option. Total capital cost was $1,500,000 in year 2000.[450]

TransAlta noted that the LP rotor life achievement program has allowed TransAlta to refurbish existing rotors without extended outages. In determining that the purchase of this rotor was the least cost option, a total of 68 scenarios were studied. The 17 lowest cost alternatives all involved the purchase of the rotor from Ontario Hydro. TransAlta noted that there are very few LP rotors available in the world that would be suitable for use in these units.[451]

Board Findings

The Board accepts the evidence of TransAlta that the purchase of the Ontario Hydro LP rotors was the least cost solution to maintaining reliable generation at Sundance. The Board notes Intervenors did not oppose this specific project. The Board approves the inclusion of this project in rate base for TransAlta in 2000.

(T) Sundance 2 Boiler Control Replacement

Position of TransAlta

The existing Sundance 2 boiler controls required replacement due to concerns with obsolescence, reliability, and serviceability. GBS Production Engineering recommended replacement of the existing boiler controls with modern controls in accordance with past practice on other TransAlta units. Estimated capital cost was $1,000,000 in year 2000.[452]

---

[450] TransAlta Application, Section 2.4
[451] TransAlta Argument, p.14-15
[452] TransAlta Application, Section 2.4

Board Findings

The Board finds that this project is acceptable to maintain generator reliability. The Board notes Intervenors did not oppose this specific project. The Board approves the inclusion of this project in rate base for TransAlta in 2000.

(U) Sundance 3 Boiler Control Replacement

Position of TransAlta

The existing Sundance 3 boiler controls required replacement due to concerns with obsolescence, reliability, and serviceability. GBS Production Engineering recommended replacement of the existing boiler controls with modern controls in accordance with past practice on other TransAlta units. Estimated capital cost was $1,100,000; $100,000 in 1999 and $1,000,000 in 2000.[453]

Board Findings

The Board finds that this project is acceptable to maintain generator reliability. The Board notes Intervenors did not oppose this specific project. The Board approves the inclusion of this project in rate base for TransAlta in 2000.

(V) Keephills—Raise Primary and Secondary Ash Lagoon Dykes

Position of TransAlta

Continued operations at the Keephills Generating Station involved the disposal of bottom and fly ash on a regular basis in accordance with Alberta Environment licensing regulations. Keephills' ash disposal system consists of primary and secondary ash lagoons and a decant pond. All water was reused for ash hydro-transport. The primary and secondary ash lagoons exchanged duties depending on which lagoon was filled and which one was ready to fill. The height of the lagoons was increased as part of an ongoing program to provide adequate storage to the end of the life of the plant.

GBS Production Engineering recommended continuing with plans to upgrade the ash lagoon infrastructure to allow the safe and efficient operation of the lagoons. In addition to raising the dykes, the proposed scope of work included construction of an additional pipeline in a new raised pumping structure. This pumping structure was required to ensure the entire pipeline system was optimized with respect to changing elevations. This project addressed the ongoing height adjustments to both lagoon dykes. This project was required to ensure continued operation of the plant and would mitigate the risk of plant derates or environmental excursions associated with dyke overflows. The estimated capital cost of the project was $2,500,000 in year 2000.[454]

[453] TransAlta Application, Section 2.4
[454] TransAlta Application, Section 2.4

Board Findings

The Board finds that this project is acceptable to maintain ongoing operations at Keephills in accordance with Alberta Environment regulations. The Board notes Intervenors did not oppose this project. The Board approves the inclusion of this specific project in rate base for TransAlta in 2000.

(W) Total Generation Capital Additions

Position of the FIRM Customers

In the 1996 General Tariff Application, the Board stated, with regards to TransAlta's accuracy in forecasting capital expenditures for rates setting purposes:

> The Board notes that, in reviewing TransAlta's comparisons of forecast to actual capital expenditures, there has been a consistent variance of 17% of "over-forecasting" during the period from 1992 to 1995 inclusive. The Board notes that for this period the total forecast capital expenditures, excluding Sheerness II, have totaled $941 million, while the actual expenditures have totaled $777 million.

The Board concluded TransAlta's "forecasting techniques may need to be reviewed." The Board went on to reduce TransAlta's 1996 forecast capital additions by 10% or $24.1 million.

For the period identified by the Board in Decision U97065 (1992 to 1995 inclusive), TransAlta experienced chronic over-forecasting for each of the four years in question, ranging from 18.1% to 23.8%. For 1996, total Company capital additions were over-forecast by $50.4 million or 26.1%. Capital additions for 1997 and 1998 were the subject of negotiated settlements and TransAlta has not provided any comparison of forecast to actual capital expenditures for these years.

In this proceeding, Mr. Way indicated that "The senior management team sets the capital budget and approves the capital budget." Increases or decreases in the budget are approved by the Executive Vice President of the business unit. The budget approved by the Board of Directors was set primarily for incentive compensation purposes. The FIRM Customers submitted that the capital budget was based on the buildup of potential projects starting at the department level and ending with final approval at the Executive Committee level. In many instances, projects contemplated within the approved capital budget never proceed or are deferred for a variety of reasons. There was nothing given in evidence to suggest that this process included a mechanism which took into account previous forecasting errors.

In response to an undertaking given by Mr. Way, TransAlta provided a breakdown of the capital additions which did not materialize and reasons for deferral in 1996. Although, the undertaking only identified four projects worth $35.7 million, the FIRM Customers noted that the deferral of

projects, projects not required, and forecasting error were the primary reasons for the difference between forecast and actual capital expenditures.

The FIRM Customers submitted it would be appropriate for the Board to make a downward adjustment of 20% for both 1999 and 2000. The FIRM Customers argued that it is not unreasonable to have regards to TransAlta's history of over-forecasting. Although independently arrived at, the FIRM Customers noted that its recommendation was consistent with the 20% adjustment made by the IAT in its 31 May 1999 Draft Report for TransAlta's Coal Unit PPAs.

The FIRM Customers also argued that this adjustment is appropriate, since TransAlta directly benefits from any reductions to Board approved forecasts and senior management also benefit through Incentive Compensation payments.[455]

In reply argument, the FIRM Customers noted that TransAlta's submission in support of its capital additions forecast was based on review and justification of a few selected projects. It did not consider the accuracy of its global forecasts, which have proven to be unrealistically high.

Although TransAlta's capital budget process was canvassed in considerable detail and evidence was presented comparing actual vs. forecast additions, TransAlta ignored the customers' obvious concerns with forecasting methods and made no attempt to explain or rationalize previous over-forecasting. There is nothing to suggest the chronic over-forecasting evident in previous Applications has been corrected in the current proceeding. TransAlta instead made reference to a handful of projects which, presumably, were intended to be reflective of its capital projects generally. The FIRM Customers do not believe such an exercise is appropriate. History indicates that many of TransAlta's projects are abandoned, deferred, or reduced in scope, rendering the original forecast and accompanying justification meaningless.

Position of ENMAX

ENMAX had numerous concerns with TransAlta's proposal to add significantly to rate base:

- the magnitude of the expenditures compared to past years was excessive especially for generation and corporate services in the years immediately prior to the PPAs;
- many expenditures were being undertaken to improve performance of generators but this is not reflected in the forecast output;
- while some expenditures may ultimately be necessary and appropriate, they were not required during these test years;
- there are some expenditures which were not required; and
- some expenses should have been capitalized or excluded.

Exhibit 66 showed that TransAlta's average annual generation additions in the period 1992-1995 were $49.3 million (excluding Sheerness) while in the 1996-1998 period the annual average

[455] FIRM Customers Argument, p.158-163

increases to $72.9 million. In the 1999-2000 forecast this rose again to an average of $85.4 million. The capital additions did not follow the trend of declining costs.

This would not necessarily have been disturbing except for the track record of TransAlta. In the 1996 General Tariff Application, the Board decided to implement a conservative 10% reduction to TransAlta's forecast of additions. ENMAX noted that TransAlta argued with the figures developed by ENMAX in Exhibit 66, claiming that the inclusion of corporate services costs rendered the analysis invalid. However, TransAlta provided no evidence as to the impact of including corporate services. ENMAX submitted that while the specific numbers may be slightly affected, the trend towards increasing costs is valid. ENMAX recommended that the Board implement a 25% reduction in forecast capital additions.

Further, TransAlta stated that there must be a reconciliation between this application and the PPAs or there could be stranded investment. TransAlta's concern with stranded investment implied that it has the incentive to curtail or postpone capital investments. This provides another reason for the Board to be cautious and conservative in its evaluation of TransAlta's forecast capital additions.[456]

Position of TransAlta

The arguments of ENMAX and the FIRM Customers with respect to capital additions considered the historical record of TransAlta with respect to forecasting capital additions. ENMAX attempted to rely on its analysis of the data[457] which TransAlta's evidence demonstrated to be invalid. ENMAX appeared to have accepted this criticism in its argument. ENMAX further stated: "TransAlta's concern with stranded investment implies that it has an incentive to curtail or postpone actual capital investment." This statement was entirely speculative as there was absolutely no evidence to support it, and it should be disregarded by the Board.

The FIRM Customers referred to the 31 May 1999 Draft Report of the IAT in order to support its request for a 20% reduction in capital expenditures. TransAlta submitted that the draft IAT report was not properly before the Board and could not be examined.

TransAlta had acknowledged historical problems with over-forecasting capital additions. For this reason, TransAlta filed a comprehensive analysis of capital projects in full compliance with the Board's Direction. All major projects were explained in detail. TransAlta also submitted that it was not helpful to compare the current Application with the results in the 1996 filing and to ask the Board to make arbitrary adjustments accordingly. There were Negotiated Settlements for 1997 and 1998, therefore there were no forecasting records available for the last two years. TransAlta submitted that it would be unfair to make a generic reduction to the 1999 and 2000 forecasts based on data three years out-of-date. The 1999/2000 capital addition forecast should be examined on its own merits. TransAlta's Application was reviewed in detail during the

[456] ENMAX Argument, p.27
[457] Exhibit 66

proceeding and several of the large capital projects were canvassed in detail during argument. TransAlta submitted that it would be inappropriate for the Board to make a general disallowance of costs as suggested by the Intervenors.[458]

Board Findings

TransAlta requested approval for $175 million for capital projects during the test years. At the Board's direction, in Decision U97065, TransAlta provided a breakdown between individual projects costing more than $1.0 million and an aggregate amount for all projects less than $1.0 million. The total of the individual projects costing more than $1.0 million was $92.2 million and the aggregate of the projects costing less than $1.0 million was $82.8 million.

From its own review, the Board has disallowed or deferred $17.1 million of the individual projects costing more than $1.0 million. The reduction is 18.6% of the total individual projects or 9.8% of the total requested capital additions.

The Board, in Decision U97065, reduced TransAlta's forecast capital additions by 10% based on TransAlta's history (1992 to 1995) of forecast to actual expenditures on capital additions. In this proceeding the Board has determined individual reductions in dollar amounts for specific projects and will address projects costing less than $1.0 million below.

The Board considers that TransAlta's history of forecasting capital expenditures can still be used as a guideline since the Board has found it necessary to reduce TransAlta's current forecast for projects costing more than $1.0 million by a similar percentage. Accordingly, the Board considers it appropriate to reduce the aggregate of the projects costing less than $1.0 million by 10% or $8.2 million for the test years.

The total reduction to capital additions is $25.3 million or 14.5%.

[458] TransAlta Reply Argument, p.9

2. GENCO
(a) Rate Base

The Board directs TransAlta, in its refiling, to remove $8.2 million of capital additions from the projects costing less than $1.0 million. The annual amounts are shown in the tables following this finding. Separate Board Findings were provided for individual projects.

TransAlta Generation Capital Additions 1999 ($ millions) Board Approved			
	1999 As Filed	1999 Board Adjustment	1999 Board Approved
Highvale Ash Hauler Replacement	5.3	(5.3)	0.0
Highvale Coal Hauler Replacement	16.9	0.0	16.9
Highvale Pit 2 Drainage Ditch	1.2	0.0	1.2
Sundance 1-4 Secondary Crusher Upgrade	1.5	(1.5)	0.0
Brazeau 2 Generator Stator Rewind	3.0	0.0	3.0
Wabamun 4 Pulverizer Refurbishment	1.0	0.0	1.0
Sundance Plant Feedwater Plant	11.5	(11.5)	0.0
Sundance 1 #7 Feedwater Heater Replacement	1.3	0.0	1.3
Sundance 1 #5 and #6 Feedwater Heater Replacement	2.7	0.0	2.7
Keephills 1 #6 Heater Replacement	1.4	0.0	1.4
Sheerness Capital	3.1	0.0	3.1
Highvale Mine Shop	0.0	0.0	0.0
Highvale Pit 2 County Landfill Move	0.0	0.0	0.0
Highvale Freehold Royalty Deferral	0.8	0.0	0.8
Spray Woodstave Pipeline Replacement	0.0	0.0	0.0
HMS Maintenance Shop	0.0	0.0	0.0
Bighorn Compensating Water Facilities	0.0	0.0	0.0
Wabamun Boiler Asbestos Removal	0.0	0.0	0.0
Wabamun 4 Waterwall Replacement	0.0	0.0	0.0
Sundance Gen Spare LP Rotor Purchase	0.0	0.0	0.0
Sundance 2 #5 & #6 Feedwater Heater Replacement	0.0	0.0	0.0
Sundance 2 Boiler Control Replacement	0.0	0.0	0.0
Sundance 3 Boiler Control Replacement	0.0	0.0	0.0
Sundance 4 #5 & #6 Feedwater Heater Replacement	0.0	0.0	0.0
Keephills-Raise Primary and Secondary Ash Lagoon Dykes	0.0	0.0	0.0
Projects < $1,000,000	47.3	(4.7)	42.6
Total	97.0	(23.0)	74.0

2. GENCO
(a) Rate Base

TransAlta Generation Capital Additions 2000 ($ millions) Board Approved			
	2000 As Filed	2000 Board Adjustment	2000 Board Approved
Highvale Ash Hauler Replacement	0.0	5.3	5.3
Highvale Coal Hauler Replacement	0.0	0.0	0.0
Highvale Pit 2 Drainage Ditch	0.0	0.0	0.0
Sundance 1-4 Secondary Crusher Upgrade	0.0	1.5	1.5
Brazeau 2 Generator Stator Rewind	0.0	0.0	0.0
Wabamun 4 Pulverizer Refurbishment	0.8	0.0	0.8
Sundance Plant Feedwater Plant	0.4	11.5	11.9
Sundance 1 #7 Feedwater Heater Replacement	0.0	0.0	0.0
Sundance 1 #5 and #6 Feedwater Heater Replacement	0.0	0.0	0.0
Keephills 1 #6 Heater Replacement	0.0	0.0	0.0
Sheerness Capital	4.4	0.0	4.4
Highvale Mine Shop	13.9	(13.9)	0.0
Highvale Pit 2 County Landfill Move	1.0	0.0	1.0
Highvale Freehold Royalty Deferral	2.0	0.0	2.0
Spray Woodstave Pipeline Replacement	2.0	(1.8)	0.2
HMS Maintenance Shop	1.7	(1.4)	0.3
Bighorn Compensating Water Facilities	8.0	0.0	8.0
Wabamun Boiler Asbestos Removal	1.0	0.0	1.0
Wabamun 4 Waterwall Replacement	1.2	0.0	1.2
Sundance Gen Spare LP Rotor Purchase	1.5	0.0	1.5
Sundance 2 #5 & #6 Feedwater Heater Replacement	0.0	0.0	0.0
Sundance 2 Boiler Control Replacement	1.0	0.0	1.0
Sundance 3 Boiler Control Replacement	1.1	0.0	1.1
Sundance 4 #5 & #6 Feedwater Heater Replacement	0.0	0.0	0.0
Keephills-Raise Primary and Secondary Ash Lagoon Dykes	2.5	0.0	2.5
Projects < $1,000,000	35.5	(3.5)	32.0
Total	78.0	(2.3)	75.7

(2) Necessary Working Capital

A Lead/Lag Study is used to determine the average necessary working capital (NWC) required to pay operating expenses (including all taxes) in advance of collecting revenues, Generally, the payment of expenses occurs in advance of the receipt of revenues, and therefore leads revenue collection.

The supply of electric service is followed by the payment of expenses, which is then followed by the collection of the associated revenues. Expenses lag the provision of service while revenue lags both the provision of service and the payment of expenses. Some expenses occur in advance of providing the service, but generally the payment of expenses occurs after service has been provided. A revenue or expense lag is measured as the interval in days from the provision of

service to the collection of the revenue or the payment of the expense. There are two separate studies involved:

- the number of lag days in the collection of revenue, and
- the number of lag days in the payment of operating expenses, income taxes, and GST.

The net lag or net lead is the difference between the number of lag days in the collection of revenue and the number lag days in the payment of operating expense. A positive number is referred to as a net lag and means that the payment of expenses precedes the receipt of revenues thereby increasing the NWC requirement. A negative number is referred to as a net lead and means that the receipt of revenues precedes the payment of expenses thus reducing the NWC requirement.

TransAlta used 1997 recorded results in the lead/lag study, and where appropriate, adjustments to reflect subsequent changes to the timing of payments were incorporated.

The following table sets out the requested GENCO Necessary Working Capital for 1999 and 2000.

		$ millions			
Cost Category	**Lag/(Lead) (% of Yr.)**	**1999 Expense**	**1999 NWC**	**2000 Expense**	**2000 NWC**
Income tax installments	7.1	93.7	6.7	100.1	7.1
Purchase Power Costs	(1.5)	40.8	(0.6)	46.8	(0.7)
Cash Operating Expense[459]	2.3	338.9	7.8	347.7	8.0
Depreciation (1/2)	11.6	51.1	5.9	54.8	6.4
Preferred equity	(0.9)	13.4	(0.1)	12.7	(0.1)
Common Equity (Ret earn)	11.6	39.3	4.6	38.8	4.5
Common Equity (Div)	(0.9)	39.3	(0.4)	38.8	(0.3)
Debt Interest	(10.1)	71.3	(7.2)	66.5	(6.7)
GST	(2.7)	51.3	(1.4)	52.9	(1.4)
Materials & Supplies (Mid)	N/A	12.4	12.4	13.5	13.5
Unamortized software	N/A	4.2	4.2	4.8	4.8
Total NWC			31.9		34.9

Source: Exhibit 59 TAU.G-5 Revised

The percentages shown in the second column above represent the net lag or net lead days expressed as a percentage of 365 days.

[459] Includes Taxes Other than Income

TransAlta noted that its Lead/Lag Study was provided in evidence[460] and no interested parties raised any objections. TransAlta submitted that the study should be accepted in full by the Board.

Board Findings

The Board has reviewed the Lead/Lag Study and has found the net lead and net lag days for each expense category to be reasonable. The Board notes that no objections were raised with respect to TransAlta's Lead/Lag Study. Accordingly, the Board approves the net lead/lag percentages shown in the above table for each GENCO expense category.

The Board notes that TransAlta has been directed to make a number of changes to the costs in each expense category. The Board directs TransAlta, in its refiling, to revise the 1999 and 2000 NWC using the Board approved costs in each expense category.

[460] Exhibit 13, Binder #1, Section 6.3

(b) Cash Operating Expense

(1) Fuel Cost

TransAlta in its application requested approval for fuel costs as shown in the following table:

TransAlta Fuel Costs (as filed)					
	Generation				
	1996R	1997R	1998CE	1999F	2000F
Quantities – Fuel and Purchased Power					
1. Fuel Gas – GJ	2,045.0	2,384.0	3,083.0	2,621.0	2,621.0
2. Fuel Coal – Tonnes	16,735.0	17,328.0	16,940.0	17,306.0	17,358.0
3. Hydro Generation (GWh)	1,754.0	1,626.0	1,859.0	1,661.0	1,658.0
4. Thermal Production (GWh)	27,844.0	28,726.0	28,005.0	28,065.0	28,128.0
5. Small Power Production (GWh)	497.0	542.0	553.0	649.0	651.0
6. Total Supplied (GWh)	30,095.0	30,894.0	30,417.0	30,375.0	30,437.0
Cost-Fuel and Purchased Power	($ million)				
7. Fuel Gas	4.3	5.8	7.0	8.9	8.7
8. Fuel Coal	72.6	72.6	75.2	78.8	83.6
9. Total Fuel Expense	76.9	78.4	82.1	87.7	92.3
General Mine Expense (GME)					
10. Fuel Gov't Royalties	5.6	5.9	5.9	5.8	5.8
11. Fuel Reclamation	3.9	3.6	4.0	16.2	16.2
12. Fuel Ash Handling	0.0	2.6	2.5	2.4	2.5
13. Fuel Non-Gov't Royalties	13.9	13.8	13.2	18.7	20.1
14. Fuel Amortize Coal Rights	1.2	1.2	1.2	8.7	8.6
15. GME General	0.0	0.7	0.8	0.6	0.6
16. Total General Mine Expense	24.6	27.9	27.5	52.4	53.8
17. Total Fuel and General Mine Expense	101.5	106.3	109.6	140.1	146.1
18. Purchased Power	2.6	(0.2)	0.2	0.2	0.2
19. Small Power Producer Payments	31.2	34.1	34.5	40.3	40.7
20. Total Purchased Power and Small Power	33.8	33.9	34.7	40.4	40.8
21. Total Fuel, GME and Purchased Power Expense	135.3	140.2	144.3	180.6	187.0

Source: Application Schedule 2.3.4

TransAlta purchases its natural gas from the local gas utility and has forecast an increase in the cost of natural gas from $1.715 to $2.693 per GJ. For the cost of coal, TransAlta has a cost of service contract for the mining operation.

This section addresses the following issues:

- Escalation
- Strip Ratio
- Coal Hauler Savings
- Hauling Distance
- Non-Government Royalties and Take or Pay

(A) Escalation

In its Application, TransAlta stated that Generation applied a 1.6% escalation to all costs in 1999 and 2000 except in cases where a specific contractual rate was known. TransAlta explained that for fuel costs, specific escalation was used as opposed to general escalation.[461]

TransAlta also stated that, in general, forecasted operating expenses reflected an increasing trend with escalation being one of the factors.[462]

Position of the Intervenors

ENMAX noted that in the 1996-1998 period coal costs increased by a total of 3.6%. In the 1999 forecast the increase is 4.8% and in 2000 a further 6.1%.[463] By comparison, inflation has been less than 2%. The major factors cited for this increase are inflation, increasing strip ratios, haul distances and royalty rates.[464] ENMAX also noted that the response to SPPA.TAU.3(f) indicates that the escalation rates will be 3-3.86%.

Further, ENMAX stated that TransAlta has forecast a number of capital expenditures geared to improving mine productivity. However, TransAlta has not reflected any improvements in mine productivity in its fuel cost forecast. ENMAX suggested that TransAlta's proposal of crediting the $3 million salvage credit for mine equipment over the 3 year period of 2000-2002[465] could partially offset any increase in coal costs by crediting all of the $3 million salvage credit in the year 2000. ENMAX considered the salvage relates to assets employed in the test years that it would be reasonable to credit the expected proceeds in 2000.

ENMAX submitted that there is little, or no, support for more than an inflationary increase.

The FIRM Customers provided common argument and recommendations respecting GENCO, TRANSCO and DISCO Labour and Materials escalation. That argument is set out in the

---

[461] Tr. p.1769
[462] Application Section 2.3
[463] Tr. p.1767
[464] Tr. p.1763
[465] ENMAX.TAU-37

GENCO section of this Decision. The FIRM Customers stated that their argument and recommendations respecting TransAlta GENCO were equally applicable, implicitly, to TransAlta Fuel Cost Escalation.

Position of TransAlta

In response SPPA.TAU-3(f) TransAlta explained that the 1999 coal supply forecast was based on June 1998 year-to-date operating history. The components were escalated for labour, fuel, oil and parts based on historical trends and or forecasts. TransAlta utilized either an on-site index or an off-site index to escalate each component of the mining contract targets. TransAlta does not track one index against the other. The overall escalation from 1998 to 1999 was forecast at 3.86% for Whitewood and 3.39% for Highvale. The escalation from 1999 to 2000 was forecast at 3.0%.[466]

TransAlta stated that the primary reason for coal cost increases in 1999 and 2000 was due to the increased strip ratio to mine deeper coal. Increased natural gas rates also contributed to the increased costs.[467]

TransAlta responded to ENMAX's allegation that TransAlta has forecast a number of capital expenditures geared towards improving mine productivity that are not reflected in increased productivity in the fuel cost forecast. TransAlta explained at[468] there are clear benefits which will result from capital expenditures, as evidenced by the reduction in coal haulers and related personnel. The reduction results in a saving of approximately $6 million over a two-year period, which is reflected, in the original filing.

TransAlta submitted that IPPSA/SPPA.TAU-3(f) explains the escalation rates for coal costs used in the filing.

TransAlta's position respecting Labour and Materials escalation is included in the GENCO Operating and Maintenance section of this Decision.

Board Findings

The Board considers that where specific contractual rates are known, those rates are preferable to a general escalation rate. The Board also considers that in the case of productivity improvements, changes in operations are not always separately identified but the forecast is calculated based on the new operating conditions.

The Board accepts TransAlta's forecast of escalation using specific rates and accepts that its forecast contains productivity improvements.

---

[466] SPPA.TAU-3(f)
[467] Application Section 2.3.3.1
[468] Tr. p.1712-1713

(B) Strip Ratios

Strip ratio is the ratio of bank cubic meters of overburden to tonnes of coal, and provides a measure of the magnitude of overburden stripping. For a strip ratio of 3.34, 3.34 bank cubic meters of overburden is removed to mine a tonne of coal.

Position of the Intervenors

ENMAX stated that the actual change in strip ratios,[469] equates to a slight decline in 1999 over 1998. In 2000 the forecast strip ratio increases modestly but this is of no assistance as TransAlta has indicated that there is no meaningful way to evaluate the impact of a one percent increase in strip ratio.[470]

Position of TransAlta

TransAlta stated that from 1998 to 1999, increasing strip ratio, increased coal burn, increased coal haul distance (offset by new HV coal haulers) and increased natural gas rates from $1.715 to $2.693/Gj contributed to the year over year change. From 1999 to 2000, increasing strip ratio is the primary reason for the increased costs.[471]

TransAlta provided the year over year cost increases for overburden removal for the Highvale and Whitewood mines, as follows:

TransAlta Overburden Removal Increase in Costs Over Previous Year $(millions)			
	Highvale	Whitewood	Total
1997	2.3	0.0	2.3
1998	1.8	0.1	1.9
1999	1.5	0.6	2.1
2000	0.5	2.6	3.1
Total	6.1	3.3	9.4

Source: CCA.TAU-11(b)

TransAlta stated that ENMAX's conclusion that the increase in costs must be primarily attributable to royalty rates is incorrect. TransAlta stated that the overburden quantity caused the coal cost increases not the strip ratio. TransAlta explained:

[469] MI.TAU.7
[470] Tr. p.1774
[471] Application Section 2.3.3.1

> Strip ratio, as I mentioned several days ago, is the ratio of overburden to coal. How that manifests itself in the mine is that the dragline takes off the overburden to expose the coal. So as I pointed out to Ms. Quinton-Campbell several days ago, that strip ratio could be the same, only more overburden is removed and more coal is released.

TransAlta submitted that the evidence is clear that one of the factors that is causing an increase in coal costs is the need to remove increasing overburden.

Board Findings

The Board agrees with TransAlta that the increasing overburden is a factor for increasing coal costs. The strip ratio, on its own, does not indicate cost changes. The Board accepts TransAlta's forecast of increases in overburden removal in the amount of $2.1 million for 1999 and $3.1 million for 2000 for both the Highvale and Whitewood mines.

(C) Coal Hauler Savings

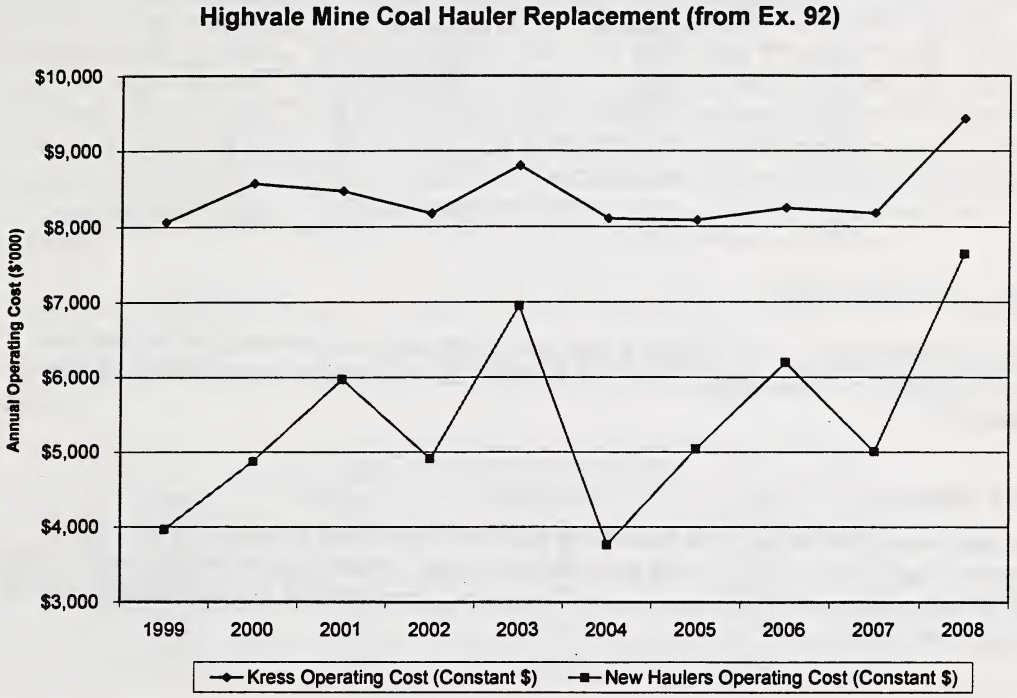
TransAlta applied to replace its existing fleet of 13 coal haulage trucks with 9 new units. The estimated savings were approximately $8.0 million during the test years.[472]

Position of Intervenors

ENMAX stated that TransAlta forecast a number of capital expenditures geared to improving the mine productivity. However, TransAlta has not reflected any improvements in mine productivity in its fuel cost forecast.

The FIRM Customers stated that the new coal haulers were forecast to be in place and working by the end of May, 1999.[473] The FIRM Customers noted that TransAlta claimed operating cost savings average of $3.0 million per year, as shown on the following table:

[472] Argument p.15
[473] Tr. p.2466



The FIRM Customers recommended that the new coal haulers be phased in over five years.

Position of TransAlta

TransAlta stated that the operating cost savings from the new Highvale coal haulers would offset the increased costs related to the increased coal haul distance.[474]

TransAlta stated that, contrary to ENMAX's allegation, there are clear benefits which will result from capital expenditures, as evidenced by the reduction in coal haulers and related personnel. Such a reduction results in a saving of approximately $8 million over a two-year period, which is reflected, in the original filing.[475]

TransAlta provided the year over year cost increases (decreases) for coal haul for the Highvale and Whitewood mines, as follows:

[474] Application Section 2.3.3.1
[475] Tr. p.1712-1713

Increase in Costs Over Previous Year $(millions)			
	Highvale	Whitewood	Total
1997	0.4	0.2	0.6
1998	(0.8)	0.0	(0.8)
1999	(1.4)	0.4	(1.0)
2000	1.2	(0.3)	0.9
Total	(0.6)	0.3	(0.3)

Source: CCA.TAU-11(b)

TransAlta stated that it "...recognized a large savings by replacing the trucks to the customer, and all we would do is essentially if we just replaced them piecemeal, we would not get that savings."[476]

Board Findings

The Board notes that TransAlta is forecasting a $8.0 million saving in respect of the capital investment for new coal haulers. The Board considers that the coal hauler savings can be attained with the new equipment. The Board accepts TransAlta's forecast of $8.0 million saving over the two-year test period.

(D) Hauling Distance

Position of Intervenors

ENMAX noted TransAlta's response that one of the major factors cited for increased fuel costs is haul distances.[477] TransAlta could not provide a calculation or formula that supports or quantifies the impact of haul distances.[478]

From information provided in MI-TAU.7, ENMAX stated that the haul distance would have minimal impact on cost increases.[479]

Position of TransAlta

TransAlta stated that increased coal haul distance (offset by new HV coal haulers) was one of the factors that contributed to the increased cost of fuel.[480]

---

[476] Tr. p.2463
[477] Tr. p.1763
[478] Tr. p.1781
[479] Tr. p.1784
[480] Application Section 2.3.3.1

TransAlta also stated that it is no big secret that coal costs are going up. They have gone up, and mining is getting into deeper cover and longer haul distances.[481] TransAlta explained that the trucks have to be on the road that much further, that much longer, and the trucks have to run longer per tonne of coal.[482] The estimates of the costs of mining this coal are from a very detailed mine study and mine plan. These average coal haul distance ratios are after-the-fact calculated indicators of the things driving the costs, but the process is not to estimate the average coal haul distance and then go to a formula to get the costs. It is a matter of a completely different detailed mine plan that gets the cost, and then calculate indicators of how some of these factors are increasing.[483]

TransAlta submitted that the costs are rising with coal haulage distance being one of the factors.

TransAlta provided the average coal haul distance for the Highvale and Whitewood mines as follows:

Average Coal Haul Distance (km)			
Year	**Highvale**	**Whitewood**	**Total**
1996	5.64	6.25	11.89
1997	6.18	6.29	12.47
1998	5.90	6.27	12.17
1999	6.43	6.80	13.23
2000	7.96	6.91	14.87

Source: MI.TAU-7

Board Findings

The Board notes that the table indicates a trend of increasing coal haul distance for the Highvale and Whitewood mines except for 1998, which indicates a minor reduction in distance.

The Board accepts TransAlta's forecast of the increased coal haul distance and the costs (as offset with the coal hauler savings) for 1999 and 2000 as filed.

(E) Non-Government Royalties

Position of TransAlta

TransAlta included in its forecast fuel costs Non-Government Royalties in the amount of $18.7 million in 1999 and $20.1 million in 2000. The issue was the relatively large increase in the

[481] Tr. p.1774
[482] Tr. p.1781
[483] Tr. p.1782

royalty payments as compared to 1998 and prior years, which were in the $13.0 million to $14.0 million range.

Board Findings

When the forecast royalty payments are adjusted to remove TransAlta's requested coal write-offs and take-or-pay write-offs, the royalty payments are within the range of the historical amounts. The results are as follows:

TransAlta Non-Government Royalties		
	$ million	
Schedule 2.3.4	**1999**	**2000**
Non-Government Royalties and Take-or-Pay	18.7	20.1
Less: Excess Highvale Coal Write-off	(2.0)	(2.0)
Westmin 82 Take-or-Pay	(3.9)	(4.3)
Total after removing TransAlta's Requested Write-offs	**12.8**	**13.8**

Accordingly, the Board approves the Non-Government Royalties Expense with the exception of the excess Highvale Coal royalty and take-or-pay charges. The Board has dealt with the excess Highvale Coal royalty (excess coal write-off) and take-or-pay issues in the Non-Cash Operating Expense section later in this Decision.

(2) Operating and Maintenance

TransAlta's GENCO O&M expenses are categorized as follows:

TransAlta-GENCO O&M Expenses (as filed)

	1996 Forecast $million	1996 Refiling $million	1997 Refiling $million	1998 Current Estimate $million	1999 Forecast $million	2000 Forecast $million
Thermal Units O&M	60.2	57.2	55.2	53.3	63.2	63.2
Share of Sheerness O&M	9.5	9.1	10.4	10.3	10.6	11.6
Hydro O&M	7.5	10.2	9.3	9.3	10.0	9.8
Insurance					5.6	5.8
Other	4.9	4.9	4.3	3.2	3.8	3.8
Pool sales mgmt., forecasting					1.7	1.7
GENCO Management, Administration, GBS, HR, Communications & Finance	11.3	10.3	10.3	14.9	12.6	13.2
Total	**93.4**	**91.7**	**89.5**	**91.0**	**107.5**	**109.1**

Source: Exhibit 124[484]

The Board has dealt with the increase in insurance premiums in 1999 and 2000 in the Self-Insurance Reserve section. The Board notes that issues were raised respecting TransAlta's forecast for Thermal Units O&M, Hydro O&M. and GENCO Management and Administration. The Board will deal with these issues in the following sub-sections.

(A) TransAlta's Thermal Units Operating and Maintenance

O&M expenses applicable to each of TransAlta's thermal generating stations were forecast as follows:

TransAlta-GENCO Thermal Units O&M Expenses

	1996 Forecast $million	1996 Refiling $million	1997 Refiling $million	1998 Current Estimate $million	1999 Forecast $million	2000 Forecast $million
Wabamun	15.2	14.6	14.5	13.4	17.5	17.0
Sundance	34.8	33.3	32.3	31.6	35.2	35.7
Keephills	10.2	9.3	8.4	8.3	10.5	10.5
Total	**60.2**	**57.2**	**55.2**	**53.3**	**63.2**	**63.2**

Analyzing the GENCO thermal O&M further, totals can be allocated between routine and planned maintenance as follows:

[484] Tr. p.3609

TransAlta Thermal Units O&M Expenses
(Routine vs. Planned)

	1996 Refiling $million	1997 Refiling $million	1998 Current Estimate $million	1999 Forecast $million	2000 Forecast $million
Routine	38.1	39.7	39.7	40.9	41.1
Planned	19.1	15.5	13.3	22.3	22.1
Totals	**57.2**	**55.2**	**53.0**	**63.2**	**63.2**

Source: Exhibit 103;[485] EAL.TAU-35, Revision 2

Position of the Intervenors

The FIRM Customers noted that the actual thermal generation O&M for TransAlta units for 1996 was about 5% less than the Board approved forecast. Like EPGI, the Board should take into account TransAlta's forecasting history when making a final determination on the appropriateness of the generation O&M forecast.

The FIRM Customers noted that TransAlta included a forecast of a 3% ($1.2 million) increase in thermal O&M routine maintenance in 1999 over 1998 and a further 0.5% in 2000. The 1999 increase included $0.8 million (a 2% increase) O&M expenses for the Wabamun water treatment plant[486] with the remainder (i.e. 1%) of the increase due to wage and contractor cost escalations. The FIRM Customers stated that although forecasted wage and contractor escalations of 2% and 6% to 7% occurred over the 1997 and 1998 period, TransAlta was still able to maintain the cost of routine maintenance at the same level over both years.[487] The FIRM Customers considered this demonstrated TransAlta's ability to achieve productivity improvements in spite of wage and contractor escalations. The FIRM Customers recommended that the Board consider productivity improvements in setting the level of generation O&M and, in particular, routine maintenance expense.

For planned maintenance the FIRM Customers did not address escalation but were concerned that TransAlta's overhaul schedule appears to follow a cycle of 6 projects during each GRA test year and somewhat fewer projects during settlement years (i.e. 1997 and 1998).

The FIRM Customers stated that given the asymmetry of information between Intervenors and the Company, Intervenors can rarely provide definitive evidence that the Company's forecast includes catch up for maintenance deferred from prior years. However, the *prima facie* evidence

[485] Tr. p.2604
[486] Tr. p.2609, l.15
[487] Tr. p.2610, l.26

suggests some maintenance may have been deferred into the test years. For example, there is no routine or major maintenance for Wabamun 4 in 1997 or 1998.[488] However, major projects are forecast for each of 1999 and 2000 at $2.7 million and $2.6 million, respectively. This is not consistent with the Company's policy on maintenance cycles, requiring at least one routine overhaul every other year. For Wabamun 2, neither major maintenance nor routine maintenance are reflected for any of the years 1996, 1997, 1998 or 1999. However, $2.3 million is forecast in 2000 for routine maintenance on LP1/Boiler. The FIRM Customers stated it is questionable whether this routine maintenance should have been carried out in an earlier year. Further, the cost of this maintenance at $2.3 million appears high given Wabamun 2 is only a 65 MW unit compared with Wabamun 4 at 279 MW. In light of the foregoing, the FIRM Customers recommended planned maintenance be reduced by at least $2.6 million in 2000 to reflect the cost of one cycle maintenance for a Wabamun unit. Consistent with historical patterns, this will result in 6 routine and major overhaul projects in 1999 and 5 in 2000.

Position of TransAlta

TransAlta responded to the FIRM Customers submission that TransAlta should be able to continue with productivity improvements to at least absorb inflationary pressures. TransAlta stated that Thermal Routine Maintenance increases reflect forecast regular labour escalation of 1.6%[489] as well as significant contractor escalation in the 6 to 7 % range.[490] Given these increases in operating labour, the net increase does reflect productivity improvements.[491] TransAlta submitted that the forecast increase in routine maintenance between 2000 and 1997 of $1.4 million or 3.5% over three years is reasonable and does reflect productivity improvement.[492]

TransAlta disagreed with the FIRM Customers submission that planned maintenance expense should be reduced by $2.6 million in 2000. The rationale provided was a theoretical discussion of planned maintenance cycles and a specific discussion of Wabamun 2. TransAlta also disagreed with the FIRM Customers suggestion that Wabamun 2 is routine work which could have been done in a prior year and that the cost is excessive when compared to a larger unit such as Wabamun 4.

TransAlta stated that the turnaround schedule used[493] clearly shows that there is not a reduction in turnarounds in 2000. As for Wabamun 2, the schedule shows no major work has been completed since before 1996 and as such, a major turnaround is now required for Wabamun 2.[494] TransAlta submitted that turnaround cost is not based solely on unit size. TransAlta submitted that there is no evidence that the cost of a turnaround for Wabamun 2 should be less than that for

[488] EAL.TAU-35, Revision 2
[489] Application, Section 2.3
[490] Tr. p.2361-2362
[491] Exhibit 103
[492] Exhibit 103
[493] Application, Section 2.2, Table 19
[494] Exhibit 103

a Wabamun 4 turnaround, and that the FIRM Customers' recommended $2.6 million reduction should be rejected.

Board Findings

In respect of the FIRM Customers' suggestion that productivity improvements should reduce or eliminate the effects of escalation the Board considers that, in the case of routine maintenance, TransAlta's increase in costs between 1997 and 2000 of $1.4 million does reflect productivity improvements.

For planned maintenance the Board agrees with TransAlta that the filed turnaround schedule provides definitive evidence for unit maintenance. Accordingly, the Board approves TransAlta's forecast for planned maintenance.

(B) Hydro Operating and Maintenance

Position of the FIRM Customers

The FIRM Customers submitted that the actual 1996 hydro O&M expense is higher than the 1996 forecast. The FIRM Customers noted TransAlta's explanation that the difference is due to the inclusion in 1996 recorded of internal use charges related to industry restructuring. It appears likely these charges were recorded elsewhere in the 1996 forecast filing and reclassified as hydro O&M in the recorded results. Therefore, the increase in 1996 actual is not the result of any under-forecasting of hydro O&M in 1996.

In 1999 and 2000, Hydro O&M increases as a result of the reclassification of $0.5 million transmission expense to part of Hydro O&M. After this reclassification, Hydro O&M still increases by $0.2 million in 1999. The FIRM Customers noted that TransAlta has successfully maintained hydro O&M at a steady $9.3 million in 1997 and 1998. The FIRM Customers stated that the forecast increase in 1999 of $0.2 million for escalation was inconsistent with recent trends. The FIRM Customers submitted the 1999 Hydro O&M forecast should be reduced by $0.2 million.

Position of TransAlta

TransAlta opposed the FIRM Customers submission that Hydro O&M be reduced by $0.2 million in 1999 because productivity improvements should absorb escalation.

TransAlta submitted that the turnaround schedule[495] clearly shows increased turnaround work is required at Brazeau 2 and Bighorn 1 and 2 in 1999. TransAlta stated that if it were not for productivity improvements implemented by TransAlta, the cost of this increased scope of work would have been higher and TransAlta submitted that a reduction of $0.2 million is not justified.

[495] Application, Section 2.2, Table 19

Board Findings

The Board agrees that TransAlta's $0.2 million increase in costs for 1999 is reasonable considering that the cost of the increased turnaround work can not be totally offset by productivity improvements.

(C) Generation Management and Administration

Position of the FIRM Customers

The FIRM Customers noted that the 1998 actual expense for this category includes a $3 million one time expense for incentive compensation. The 1998 expense also includes a transfer of $1.0 million from corporate services, not included in the 1997 expense of $10.3 million.[496] The $1 million transfer is to be an ongoing cost. Accordingly, the normalized 1998 expense would be about $11.9 million compared to a normalized 1997 cost of $11.3 million ($10.3 + $1.0 million). Additional increases in 1999 and 2000 over historical levels are primarily due to labour escalation of 5.9% in 1999.[497] A further 4.8% escalation is forecast for 2000.

The FIRM Customers submitted that the escalation in this category of costs should be zero. Specifically, the FIRM Customer noted the Company successfully maintained the $10.3 million level in 1996 and 1997 despite inflation. Further, consideration should be given to productivity improvements due to investments in information systems requested elsewhere in the application. One example would be the request for expenditure of $11 million for IT projects to continuously improve productivity.[498] As a further note, there was also an 8.8% reduction in this category of expense from the 1996 forecast to 1996 actual.

The FIRM Customers recommended that the 1999 and 2000 forecasts for generation management, administration etc. be reduced by $0.7 million in 1999 and $1.3 million in 2000 to bring the forecast down to the 1998 normalized level.

Position of TransAlta

TransAlta provided an explanation to the FIRM Customer's submission that Generation Management expense should be reduced by $0.7 million in 1999 and $1.3 million in 2000. TransAlta noted that the FIRM Customers based the proposed reduction on an analysis, after normalizing for incentive compensation in 1998, of Exhibit 124 at Tr. p.3609 and concluded that Generation should have been able to make productivity improvements such that escalation was effectively zero.

TransAlta explained that Exhibit 124 includes in-scope incentive compensation for the each of 1998, 1999 and 2000. TransAlta stated that it has committed to reducing the Application by the

[496] Exhibit 124, Tr. p.3610
[497] Tr. p.3611, l.16
[498] Tab 5.2-AFE Summary

amount of in-scope incentive compensation. The FIRM Customers analysis requires normalization for in-scope incentive compensation 1999 and 2000. TransAlta submitted that after accounting for incentive compensation and escalation, the changes are not significant and the Generation Management should not be reduced.

Board Findings

The Board notes TransAlta's statement that it will remove the inscope incentive compensation from Generation Management expense for 1999 and 2000. Therefore the Board directs TransAlta, in its refiling, to remove incentive compensation in the amount of $1.7 million[499] for GENCO ($0.3 million), TRANSCO ($0.5 million) and DISCO ($0.9 million) as well as any amount included in the Corporate Services forecast for in-scope incentive compensation in 1999 and 2000.[500] Having made this adjustment, the Board then agrees with TransAlta that, when 1999 and 2000 Generation Management expense is normalized in the same manner as the 1998 expense, the escalation is reasonable.

(D) Labor and Material Escalation

Position of TransAlta

TransAlta stated that Generation applied a 1.6% escalation to all costs in 1999 and 2000 except in the case where a specific contractual rate was known.

For Generation's 1999 & 2000 forecast, a 2% vacancy rate for employee positions and a 1.6% escalation rate was assumed. The overall trend from 1996 to 2000 highlights an increase in gross labor. This is due to labour escalation. Gross labour for 1998 and 1999 factor in additional changes other than escalation. In 1998, Generation acquired 10 additional staff due to decentralization from Corporate Services, primarily in the area of Finance, Human Resources and Communications. In addition, 17 staff were hired for Generation capital management. These staff increases adjusted the TransAlta engineer to engineering consultant ratio closer to the goal of 2:1. This adjustment provided Generation with increased flexibility to react to fluctuations in capital spending and reduce consultant costs. The decrease from 1998 to 1999 is due to the fact that 1999 and 2000 excludes incentive compensation for out of scope staff whereas it is included in 1998 actuals. Incentive compensation for out of scope staff is $1.4 million. The decrease is also due to the impact of the Generation reorganization. There is a forecast reduction of 6 staff members due to the reorganization. These decreases are offset by the addition of 7 positions from Transmission and Distribution.

[499] Exhibit 169
[500] Exhibit 59

Board Findings

The Board notes that TransAlta forecast a 1.6% escalation for all generation costs except where a more specific contractual rate was known. The Board agrees with TransAlta's use of specific contractual rates where they are known.

The Board accepts TransAlta's general escalation factor of 1.6% and the use of specific contractual rates for labour and materials in the forecast test years of this proceeding. The Board considers a 1.6% overall rate to be a reasonable escalation factor for the forecast test years. Further the Board similarly accepts these same escalation rates for TRANSCO, DISCO and Corporate Services as noted in those sections elsewhere in this Decision. The Board also accepts TransAlta's explanation of the reorganization changes affecting the number of positions by business unit and notes that the 10 staff were transferred from Corporate Services.

The Board also notes that in the TransAlta Pension Reserve Section of this Decision the Board approved a reduction to pension expense, which will in turn reduce the operating labour component of GENCO cash operating expenses.

(3) Taxes Other Than Income Tax

TransAlta forecast taxes other than income of $22.3 million for 1999 and $22.7 million for 2000 for the GENCO business unit.

Position of the FIRM Customers

TransAlta forecasted property taxes for thermal generating plants to increase by 2% in 1999 and 2000.[501] On the other hand, EPGI forecasted its property taxes will increase by 0.18% in 1999 and 0.81% in 2000.[502] Reviewing the record, it appears there is little, if any, reason to explain why TransAlta's property taxes should increase at a significantly faster rate than EPGI's.

TransAlta's property tax forecast is even more puzzling when one takes into account the settlement of the 1998 property taxes for the Wabamun Plant. The settlement results in an assessment reduction of approximately $7.9 million. Applying the mill rate for Wabamun results in a tax reduction in excess of $180,000.[503] This represents approximately 1.0% of the taxes paid by TransAlta on thermal generating plants in 1998. TransAlta also confirmed that the 1998 reduction in property taxes for Wabamun is carried forward into 1999.[504]

Given the relative forecasts by EPGI and TransAlta and the tax reduction for Wabamun, the FIRM Customers submitted the property tax forecast by TransAlta for 1999 and 2000 is

[501] Enmax.TAU-71
[502] Exhibit 48
[503] ENMAX.TAU-71
[504] Tr. p.2709

overstated. The FIRM Customers recommended the TransAlta forecast be reduced to bring it more in line with EPGI's forecast.

Position of ENMAX

ENMAX proposed a global adjustment to the total GENCO, TRANSCO and DISCO property taxes. ENMAX submitted that the Board should reduce the total amount allowed for taxes other than income taxes by $2 million for each of 1999 and 2000 to reflect current trends. ENMAX suggested that the forecast should not include increases that will not materialize.

Position of TransAlta

TransAlta noted that the FIRM Customers attempted to compare property tax escalation factors between EPGI and TransAlta. With respect, this is not a true "apples to apples" comparison. TransAlta is dealing with over two hundred municipalities including the County of Parkland for Sundance and Keephills and the Village of Wabamun for the Wabamun plant, while EPGI is primarily dealing with the County of Leduc for Genesee and the City of Edmonton.

TransAlta submitted that the ENMAX submission that taxes other that income be reduced by $2.0 million in each of 1999 and 2000 has not been supported by any credible evidence in this proceeding. Given the evidence on the record, TransAlta submitted that the Intervenor arguments with respect to property tax are without merit and ought to be rejected.

Board Findings

The Board notes that, in a previous section of this Decision, TransAlta was directed to establish a deferral account for the year 2000 for GENCO taxes other than income if assessment rules are changed and are applicable to the 2000 tax year. The Board in this section will determine an appropriate test year forecast for 1999 and an appropriate base line forecast for 2000 GENCO taxes other than income.

The Board notes that TransAlta proposed a total Utility forecast for GENCO, TRANSCO and DISCO of $45.2 million in 1999 and $45.7 million in 2000 for taxes other than income. These figures included $1.0 million in 1999 and $1.1 million in 2000 for water rentals that form part of the GENCO taxes other than income forecast. The Board notes that the $2.0 million reduction proposed by ENMAX for the combined business units translates into an approximate 4.5% reduction to TransAlta's forecast excluding water rentals. The Board for reasons set out in the DISCO cash operating cost section of this Decision rejects the ENMAX proposal to reduce each of GENCO, TRANSCO and DISCO by 4.5%.

The Board has reviewed TransAlta's reasons for the forecast increase for taxes other than income tax. The Board accepts that TransAlta is dealing with different municipalities than EPGI. The Board notes that TransAlta is proposing a 2% increase to GENCO property tax for 1999 and 2000. The Board accepts these increases as reasonable and appropriate. Accordingly, the Board

approves a GENCO forecast of $22.3 million for 1999 and $22.7 million for 2000 for taxes other than income.

(c) Non-Cash Operating Expense

(1) Amortization of Coal Costs

TransAlta reviewed its coal assets to determine the amount of coal required to fuel existing regulated generating units. TransAlta stated its review was driven by the change in legislation and the PPA process. TransAlta determined that it had coal in excess of the requirements of regulated generation and proposed to recover the costs of the excess coal over the two-year test period. The proposed amortization of the excess coal costs is summarized below:

- Excess Outside Coal (Coal not associated with any existing regulated generating units)
  - $9.6 million remaining rate base balance to be written off ($4.8 million/year)
- Excess Highvale Coal (Westmin 82 take or pay coal associated with the Keephills and Sundance plants)
  - (Proposed expensing of $4 million ($2 million/year) previously capitalized take or pay payments)
- Westmin 82 take or pay payments in 1999 and 2000 for coal associated with the Keephills and Sundance plants
  - (Proposed expensing of $3.93 million in 1999 and $4.25 million in 2000 rather than current method of capitalizing and then expensing when the coal is mined)

TransAlta commissioned a study into reclamation costs and proposed that deficiencies in past levelized reclamation costs also be recovered over the two-year test period as follows:

- Levelized Reclamation Costs
  - $14.4 million ($7.2 million/year)

The Board will deal with each of the coal cost claims separately in the following sub-sections.

(A) Excess Outside Coal

TransAlta has in its rate base $32.1 million of outside coal rights held for future generating plants which is not needed to fuel its existing generating plants. TransAlta has reduced this amount by $21 million with respect to economy energy sales leaving a balance of $11.1 million, which TransAlta characterized as a "stranded cost." TransAlta proposes to write off this amount by amortizing the balance equally over 1999 and 2000.[505]

[505] TransAlta Evidence, Section 2.5.1

Upon further review of these coal rights for future generating plants, TransAlta found $1.5 million of the Highvale Mine coal (acquired in 1971, 1977, 1978, 1984) may have value in the period 2001-2020 for the existing power plants by providing some flexibility and alternatives in mine planning. Therefore, TransAlta proposed not to amortize this $1.5 million in 1999 and 2000 and leave this amount in rate base.[506] As a result, TransAlta revised the amount to be written off from $11.1 million to $9.6 million. TransAlta proposed to write down the net $9.6 million dollar cost of coal rights not required for existing plants at the rate of $4.8 million per year for each of 1999 and 2000.

The $30.6 million ($32.1-$1.5) expenditures for these coal rights were made in the period 1971 to 1984 to acquire coal at Judy Creek North, Camrose Ryley, Red Deer, and across the province (Dome). The $21 million "coal acquisition prepayments" revenue was accumulated in the period 1977 to 1982 from pre-EEMA economy energy sales to Edmonton Power, B.C. Hydro, and Alberta Power Limited and was credited to capital in recognition of the need to acquire coal and replace reserves utilized in creating the economy sales.[507]

The Board, in Decision E89091, approved the rate base inclusion of all the coal assets TransAlta had acquired for future potential generating plants. The tonnage of coal associated with future generating plants is 2.638 billion tonnes. At current consumption of about 17 million tonnes per year, this represents about 155 years of generation. Of this amount, 526 million tonnes is associated with the Highvale Mine, at a cost of $1.5 million, which TransAlta now states may have some value in the 2001–2020 period. In 1998, leases associated with the Red Deer underground crown coal rights (807 million tonnes) were allowed to lapse. Therefore, the tonnage associated with coal rights for future generating plants is now 1.305 billion tonnes (2.638 billion-526 million-807 million tonnes), or about 77 years worth of generation.[508]

These reserves are not required for the base or life extension PPAs and their development is not foreseen at this time. As the prudence of the investments and the accounting practices used by TransAlta were accepted by the Board in Decision E89091 and prior GRAs, TransAlta believed it was appropriate to amortize these expenditures over the next two years. TransAlta also submitted that it is proper that these assets be written down in the period and in the general regulatory context in which the benefit of holding these resources was realized and not in some undefined future period and in the context of a changed regulatory paradigm.

Position of the FIRM Customers

The FIRM Customers considered there were two issues to resolve:

- the amount of "stranded cost" for surplus coal, if any, and
- the appropriate regulatory treatment to be accorded this surplus coal and related costs.

[506] CCA.TAU-16
[507] TransAlta Evidence, Section 2.5
[508] CCA.TAU-16(a)

Stranded Cost of Surplus Coal

TransAlta claimed the stranded cost of surplus coal, as amended, is $9.6 million comprising the original cost of $30.6 million less the credit from economy energy sales of $21 million.

The FIRM Customers considered that TransAlta had improperly reduced the surplus coal cost by applying the $21 million credit earned from economy energy sales. The evidence is clear the economy energy sales were derived from coal associated with the current generating plants.[509] The correct treatment of these economy energy sales would have been to give credit to the customers at the time the sales were made. This, however did not occur and the credit was booked as an offset to the cost of coal inventory. The fact this regulatory accounting treatment afforded these sales for a period of time should not cloud the issue of the cost of the surplus coal held by TransAlta. In fact, TransAlta agrees it had the option of treating the $21 million of economy energy sales as "coal associated with existing plant, not excess coal."[510]

Further, TransAlta was asked in CCA.TAU-16 (a) to provide a specific reference to a prior Board Decision or direction approving the application of $21 million credit against the coal resources held for future plants. TransAlta provided a "summary response" to this IR without ever providing a specific response to this question. When pressed at the hearing to provide justification for crediting future coal costs, TransAlta referred to Board Decision E89091, quoting the following passage:

> The Board considers that customers (past, present and future) have, and will benefit from the results of the past regulatory treatment accorded coal rights and leases. Further, the Board considers that it would be unfair to investors to "change the rules" and transfer coal reserves now held in Rate Base to PHFFU, thereby substituting cash return with a more uncertain non-cash return, in circumstances where customers are benefiting from the past regulatory treatment and where circumstances remain substantially unchanged from the Board's past Decisions.[511]

With respect, nowhere in the foregoing passage does the Board direct the Company to specifically apply the credit earned on economy energy sales to coal costs acquired for future generating units. Even TransAlta's witness expressed doubt whether the above quote can be construed as a direction from the Board.[512] It is clear, however, TransAlta has on its own accord decided the appropriate treatment of the economy energy sales, not booked as current income at the time earned, was to arbitrarily reduce the costs of an asset never used in the first instance to generate the sales. The FIRM Customers submitted it is not appropriate to use the credit accumulated to reduce the costs of a potentially stranded asset. The issue is what is the

[509] Tr. p.2842
[510] Tr. p.2844
[511] Decision E89091, p.99
[512] Tr. p.2850

appropriate treatment of the surplus coal held by TransAlta given its original cost of $30.6 million.

TransAlta referred to Rate Case 6 where it indicated "the $21.0 million fuel displacement reserve accumulated from economy energy sales was credited to capital in recognition of the need to acquire coal and replace reserves utilized in creating the economy sales."[513] The need to "acquire coal and replace reserves utilized in creating the economy energy sales" was explained by TransAlta in the current proceeding as follows:

> We were selling economy energy to primarily Edmonton Power at the time and displacing gas-fired energy, and so I think part of the rationale here for putting aside some of this money was that by making those additional sales, we were consuming coal, and we recognized quite early on that this was some of the cheapest coal in the mine that we were consuming.
>
> As we said before, we started off with the coal that was the shallowest and close to the plants, so it was the cheapest coal, and so part of what we were concerned with was we were making these sales to Edmonton Power, displacing their gas, but it was actually going to force us more quickly into more expensive parts of the mine later, and at some point, it could even have resulted that we had to replace, go out and buy additional reserves of coal to replace that coal that we used or consumed for these economy sales.[514]

Considering TransAlta had more than adequate coal reserves to fuel existing generating plants at the time the economy energy sales were taking place, and TransAlta was well aware of this fact, there was no need to go out and purchase additional reserves to replace coal used up in the economy sales.[515] The fact TransAlta is now before the Board requesting the write off of all remaining excess coal procured for future generating plants is further testament to the fact there was no such need. In addition, none of this coal was actually used to generate the economy energy sales. Therefore, the logic of applying the $21 million credit to coal procured for future generating plants is ill conceived

The economy energy sales took place in the 1977–1982 period whereas the coal purchases took place at various times between 1971–1984.[516] The need to acquire coal, we submit, was driven primarily to provide options with respect to potential new generating plants. This fact was recognized by the Board in Decision E89091, as follows:

---

[513] TransAlta Evidence, Section 2.5
[514] Tr. p.2837
[515] Tr. p.2838
[516] CCA.TAU-16(a)

> The Board considers that the past regulatory treatment of coal rights and leases has enabled TransAlta to establish and maintain an interest in coal reserves adequate to ensure options needed to fuel existing and future generating plants at a reasonable cost.[517]

Economy energy sales have in fact continued but no further credit of these sales is applied against the coal held for future generating plants. Mr. Way explained as follows:

> No, those sales continued on even to -- I believe what happened was a bit of a change in structure. We moved to a power pool environment, and the sharing associated with those sales was altered somewhat, and so the, I will say, allocating of some of that benefit to future customers also ceased at that time. This was tied into the EEMA averaging or the EEMA legislation that occurred in about 1982.[518]

It is clear from the above evidence the economy energy sales credited to the coal was intended to offset the higher costs of mining the coal deeper and further away from the plant as the cheaper coal got used up in making the sales. Application of the credit against coal not directly associated with the production of the energy that generated the credit does not make sense. Such treatment would give TransAlta an economic and unfair advantage over other potential generators in competition for future plant.

The FIRM Customers submitted the reality of the economy energy credit is that it should be applied against the existing coal required for existing plants. The outside surplus coal should be reviewed on the basis of its original cost. Solutions to dealing with this coal may involve the use of the credit if deemed appropriate by the Board.

Regulatory Treatment of Outside Surplus Coal

It is a well-accepted regulatory practice where new evidence is presented to the Board, it may revisit an issue previously decided in an earlier Board order. The Board took note of this practice when it stated:

> The Board notes the position of LE/RD, the REA/AAMDC and the AHA to the effect that regulatory principles do not preclude revisiting an asset previously allowed in Rate Base when new evidence or a detailed scrutiny of the requirement of that asset is undertaken. While the Board accepts this argument in principle, in the instant case, the Board has not been presented with sufficient evidence respecting changed circumstances which would persuade the Board to deem inappropriate the determinations made in its past Decisions.[519]

---

[517] Decision E89091, p.98
[518] Tr. p.2835
[519] Decision E89091, p.98

In fact, the Board in Decision E89091 applied the foregoing principle in dealing with the treatment previously accorded to the Camrose-Ryley coal and land rights. Costs associated with the Camrose-Ryley coal and land rights were initially included in rate base in 1975.[520] Later, the Board determined the costs associated with the Camrose-Ryley coal and land rights should be removed from rate base and held in PHFFU and the costs associated with site investigation amortized over five years.[521] In Decision E89091, the Board, after an extensive review, concluded all coal rights should be allowed in rate base including the Camrose-Ryley coal and land rights.

The FIRM Customers submitted that the Board has compelling and persuasive evidence in these proceedings to alter its findings in previous Decisions that coal associated with future generating plants should be held in rate base. Circumstances have changed significantly since the time these outside coal assets held for future needs were included in rate base. These changed circumstances suggest these assets should be removed from rate base in 1999 and 2000 as they are not required. The major change, of course, is mandated by the implementation of the EU Act, which no longer imposes a legislated obligation on TransAlta and other "regulated" electrical Utilities to provide the next source of generation supply. Without such an obligation there is no need to hold in rate base an asset that will not be used in the regulated world.

The FIRM Customers noted TransAlta's position that the development of future coal assets "is not foreseen at this time."[522] At the hearing, TransAlta stated it did not expect to utilize these assets even during the PPA period. Clearly this represents a material changed circumstance. In the past, when the Board allowed these assets in rate base, the understanding was that these assets would be needed to "fuel existing and future generating plants at a reasonable cost."[523]

In addition, the Board, in its past Decisions, approved the need for TransAlta to purchase the coal rights for potential future generating units as a risk mitigating strategy. The evidence as summarized in Decision E89091 indicated coal comprises 25% of the lifetime costs of a thermal power plant and the cost of coal held for future plants was small in relation to the lifetime cost of the energy from the plant. In essence, TransAlta was purchasing an asset, the capital costs (return and income taxes) of which acted as a form of insurance, that would mitigate energy costs for future potential power plants in the regulated world.

Customers never asked TransAlta to acquire what has now turned out to be a speculative asset and, in fact, in earlier proceedings have questioned the need for these outside coal assets and their inclusion in rate base as assets required to provide service. However, to the extent it provided some form of insurance, the Board approved the carrying costs of the asset. Since 1996, with the passage of the EU Act, customers have continued to pay for the capital costs, or

[520] Decision E75069, p.19-20
[521] Decision E85129. p.73
[522] TransAlta Evidence, Section 2.5
[523] Decision E89091, p.98

insurance costs of approximately $4 million per year, of a risk mitigating strategy no longer required in the EU Act world. While there may be questions as to the reasonableness of customers paying for a now defunct "insurance policy", the issue is what to do with this now apparently stranded asset and if it is to be written off, who should pay and how much should they pay?

TransAlta takes the position this coal has no value. Specifically, it states:

> With the new regulatory framework being developed for 2001-2020, TransAlta has determined that certain coal assets, namely Judy Creek, Camrose Ryley, Dome and Red Deer Freehold are not required for future regulated power generation. It is therefore prudent that these assets be written down to their real value, which TransAlta believes, based on relatively recent attempted sales of Alberta plains coal assets by others, to be close to zero. It also seems prudent that these assets be written down in the period in which the benefit of holding these resources was realized and not in some future period.[524]

TransAlta does not seem to consider the fact such coal may be used for future "non-regulated generation." TransAlta's claim that it does not "see a future for it in the unregulated power production either," is pure speculation at this time.[525] It is conceivable in time, with changing technologies and world markets, this coal may indeed become valuable.

TransAlta's reluctance to give up ownership of these rights is troublesome. It states these rights, even if the associated costs are written off completely by 2000, will stay with TransAlta until "disposition of them sometime in the future."[526] Further, Mr. Way stated:

> So I think our position is that customers do not own these rights, and customers would see no value....and make it clear that customers have received the value from these during all the years when the plants were being planned and built.[527]

It also appears strange TransAlta would, on the one hand say the coal rights associated with future generating plants are worthless and yet, not want to put these rights up for sale or allow the associated leases to lapse.[528] TransAlta stated these reserves are not required for the PPA period but does not discount the possibility they may be needed at some time thereafter. TransAlta states "their development is not foreseen at this time."[529] However, that does not mean their development may not materialize in the future. TransAlta relies on the recent attempted

[524] CCA.TAU-16
[525] Tr. p.2848
[526] Tr. p.2821
[527] Tr. p.2821
[528] Tr. p.2825, p.2830
[529] TransAlta Evidence, Section 2.5.1

sales of Alberta plains coal by others, but has done no independent market assessment itself to determine if its outside coal has any market value.[530]

TransAlta was quite willing to let lapse the Red Deer Underground Crown leases[531] which had 850 million tonnes of coal. The $2.8 million of costs associated with this coal is still in rate base. However, when asked why it was not willing to let the other leases to similarly lapse, TransAlta stated these assets have "a book value."[532] With respect, this logic makes no sense and is contrary to the treatment of the Red Deer underground crown leases. Surely, if an asset has no market value, of what relevance is the book value?

As Mr. Drazen observes:

> TAU wants to charge customers several million dollars of stranded coal costs. In other jurisdictions, recovery of stranded cost is conditioned on Utilities mitigating them, usually by assets sales.[533]
>
> So once you put it to the market test, then at least you have got some reassurance that you know it is either worthless or you have got some money. Until you do that, it seems to me, it is an academic exercise where the Utilities have the incentive to say it is worthless as long as they can get the customers to pay it.[534]

TransAlta's vague reference to the "general regulatory context in which the benefit of holding these resources was realized" does not assist the Board nor Intervenors in assessing why the cost of these assets should be written off in the period 1999/2000. By implication, TransAlta suggests that these coal assets had full value right up to the commencement of the 1999/2000 test period. TransAlta's assertion that these assets have no value must be questioned in light of the fact that it did not seek a write-down of these assets in its 1996 GTA — certainly there is no evidence that these assets became worthless overnight and TransAlta has not put them to a market test.

TransAlta recommended that the Board treat this coal as a stranded cost and write it off over the two test years. Their recommendation is based on netting the economy energy credit of $21 million against the cost of $30.6 million.

Stranded costs are prudent costs of assets acquired by a Utility to provide service to customers that are no longer required and have a value lower than recorded cost. In this case customers have questioned the prudence of the surplus coal acquisitions over the years as evidenced by the

[530] Tr. p.2849
[531] CCA.TAU-16
[532] Tr. p.2825
[533] Tr. p.4318
[534] Tr. p.4408

commentary in past Board decisions. The FIRM Customers believed this fact must be considered by the Board in making its decision on these costs.

Additionally, given the move to a competitive market for generation supply the Board must avoid conferring a competitive advantage to TransAlta by allowing it to retain assets with the potential to be used for generation at zero cost.

Based on the lack of a market test at this time for this coal and TransAlta's apparent interest in holding on to these properties, the FIRM Customers recommended the $30.6 million be removed from regulatory service at book value. TransAlta's unregulated business can then deal with the properties as they see fit. This is the original cost of the properties and given the questioning of the prudence of some of TransAlta's past decisions would seem a fair outcome for customers and TransAlta. The Company's management can then decide how best to maximize the return on these properties.

However, if the Board accepts TransAlta's position these properties have no value and are truly prudent stranded costs then all efforts must be taken to maximize recovery on the assets for the benefit of consumers. In this case the FIRM Customers would accept utilization of the $21 million economy energy credit to reduce the loss and recommended the Board transfer the net cost of $9.6 million to TransAlta's unregulated business for TransAlta's management to deal with as they see fit. Management must have some incentive to act aggressively in dealing with these properties. Customers have paid the carrying costs of assets that they have questioned as "used or required to be used" for many years. To give these properties to TransAlta at no cost would be a travesty. Customers should not be asked to cover the remaining cost.

The FIRM Customers did not believe the "changed regulation paradigm" should drive the immediate write off of these so-called "stranded costs." The FIRM Customers contended that the amount that may be considered stranded is not known, and further, consumers have more than paid for any benefits that may have been realized from holding this coal for future plant. The FIRM Customers recommended the Board transfer these assets at book value to TransAlta's unregulated activities resulting in no gain or loss requiring amortization.

Position of ENMAX

In Section 2.5.1 of its Application, TransAlta offered the following quote from Decision E89091:

> The Board has reviewed the evidence filed in respect of the appropriate accounting and regulatory treatment of coal properties held for future potential power plants and finds it reasonable to include such coal properties in Rate Base.[535]

[535] Decision E89091, p.97

As a result of this Board Decision, the costs associated with these coal rights have been included in TransAlta's tariffs since 1989. However, TransAlta now takes the position that the coal reserves are not required for the base or life extension PPAs.[536]

The EU Act, section 45.4, deals with the proposals that are to be provide to the IAT. Section 45.4(6) of the EU Act states:

> **45.4(6)** The owner of the generating unit shall also provide, not later than August 31, 1998, information relating to reasonable costs over the effective term for coal rights or any other property that have been approved by the Board for inclusion in the owner's tariff, where the rights or other property is not attributable to any particular generating unit. [emphasis added]

The Coal Rights Held for Future Generating Plants are listed in CCA.TAU-16. They are referred to as Judy Creek, Camrose Ryley, Red Deer and Others (Dome, Crown). These coal rights are not associated with any existing generating unit, as these reserves are not required for the base or life extension PPAs.

Clearly these coal rights meet the criteria required by section 45.4(6) of the EU Act in that they are:

- coal rights or other property that have been approved by the Board for inclusion in the owner's tariff. TransAlta has had these assets in rate base since 1989; and
- rights or other property not attributable to any particular generating unit. TransAlta acknowledged in Section 2.5.1 of their application that, "These reserves are not required for the base or life extension Power Purchase Agreements..."

Clearly, the prudent action for TransAlta was to include these costs in the proposal to the IAT filed on 30 October 1998. The EU Act, section 45.5(2)(c), requires the IAT "to determine the reasonable costs for coal rights or any other property referred to in section 45.4(6)..." In addition, section 45.96(6) of the EU Act states:

> **45.96(6)** Any amount determined by the independent assessment team under section 45.5(2)(c) or 45.7(2) shall be paid out of the balancing pool in accordance with the regulation.

Therefore ENMAX has concluded that the EU Act intends assets such as these to be a part of the proposal going forward to the IAT and the EU Act also requires the IAT to accept them.

[536] Tr. p.1815

TransAlta has made no attempt to determine whether the coal rights have any market value. While acknowledging that the coal may have some value in the future,[537] TransAlta has simply based its determination of no value on its assessment of its needs through the PPA period.[538] One method of determining value is the placement of the asset on the market for sale. Despite this, TransAlta have made no attempt to market the coal rights[539] although they retain ownership after the write off and after the PPA period.

TransAlta has chosen to ignore the EU Act and amortize these assets over 1999 and 2000 while still retaining ownership of the coal rights.[540] Intervenors can only speculate why TransAlta has chosen to write off these assets now rather than following the requirements of the EU Act. It is certainly possible that TransAlta may repower some of its units after the expiry of their useful lives and the written off coal would be used at that time. This would result in a mismatch of costs and benefits between generations of customers.

Section 45.4(6) of the EU Act deals with stranded coal rights that are not attributable to any specific generating unit but which have been approved by prior Board decisions. The EU Act contemplates that these assets should be included in the IAT process. ENMAX recommends that the costs associated with the written off coal rights should be removed from the revenue requirement in 1999/2000, should be included in the IAT proposal and be written off from 2001 to 2020 in accordance with section 45.5(2)(c) of the EU Act. In the alternative, if TransAlta has lost the opportunity to include costs in the IAT process, the coal rights held for future generating plants should be transferred to the DISCOs and the TA in proportion to their reservation percentages. It then becomes the responsibility of the DISCOs and the TA to determine if the coal rights should be retained for future benefit or sold.

Position of LE/RD

With respect to the outside coal, the consensus appears to be that while the purchase represented an insurance policy in terms of options for current and future customers of the utility, the coal is essentially now of no value to customers and should be written off.[541] LE/RD opposed the accelerated write off of this investment, and given that it was acquired for all future customers LE/RD submitted that it should be written off over the balance of the regulated life of the TransAlta coal units, and not over the two-year period proposed. LE/RD also noted that the driving force for the proposed accelerated write off is the uncertain effect of the PPA process.[542] LE/RD submitted that this is not a sufficient reason to effect recovery in the fashion proposed. The pain of this valueless purchase should be borne by more than just the 1999-2000 customers.

---

[537] Tr. p.2821
[538] Tr. p.2847-2848, p.2369-2370
[539] Tr. p.2849-2850
[540] Tr. p.2821
[541] Tr. p.2367-2368
[542] Tr. p.2370

At pages 16 to 18 of its argument, TransAlta deals with its proposal to recover certain costs associated with coal and reclamation on an accelerated basis. TransAlta presents no compelling reason why customers in the years 1999 and 2000 should pay the entire costs of the outside coal rights. Essentially, TransAlta's argument is that its proposal is reasonable and should be approved. There is no suggestion that the customers in 1999 and 2000 receive any greater benefit as a result of these costs than future customers over the life of the regulated generating units will receive. LE/RD submitted that TransAlta's argument provides insufficient justification to permit the accelerated costs recovery as sought in the application, and that all such costs should be amortized over the remaining regulated life of the coal mine and related units.

Position of TransAlta

Intervenors questioned why TransAlta had not attempted to sell or auction the assets in some way. Mr. Way provided a clear indication that the costs of attempting such a sale cannot be justified.[543]

ENMAX suggested that the costs associated with outside coal rights should be removed from the revenue requirement in 1999/2000, and should instead be included in the IAT proposal to be recovered from 2001 to 2020 in accordance with section 45.5(2) of the EU Act. Similarly, LE/RD submitted that these coal rights should be recovered over the balance of the regulated life of the TransAlta coal units. Finally, the FIRM Customers initial position is that the $30.6 million should be removed from regulatory service at book value. In the alternative, the FIRM Customers would accept utilization of the $21 million economy energy to reduce the loss, then propose a transfer of $9.6 million to TransAlta's unregulated business.

TransAlta's prudent coal acquisition policy and the cost/benefit and accounting treatments of its coal acquisitions have been the subject of thorough examination at prior proceedings and have been previously vetted and approved by the Board. TransAlta submitted that it would be inappropriate for the Board to turn back to the first time these matters were reviewed in 1975, change accounting treatment in hindsight, and disallow recovery of expenditures that have been previously found to be prudent. As stated in CCA.TAU-16(a-c), TransAlta believes that these costs should be recovered in the period in which the benefit of holding these resources was realized, and not in some future period. Similarly, the credits for $21 million to the coal rights account should accrue during this same period.

Board Findings

The Board accepts, the amount of $30.6 million as the original cost of the excess outside coal included in rate base. The Board notes that TransAlta shows a total amount of $95.6 million (net of the $21 million credit) for all coal and mineral rights included in rate base as of 1 January 1999.[544]

[543] Tr. p.2830-2831
[544] Exhibit 60

The Board agrees with TransAlta "that it would be inappropriate for the Board to turn back to the first time these matters were reviewed in 1975, change accounting treatment in hindsight, and disallow recovery of expenditures that have been previously found to be prudent."[545]

The Board agrees with the FIRM Customers that there has never been a specific regulatory determination that the $21 million should be deemed to be a credit against the $30.6 million excess outside coal costs as opposed to a credit against the entire $116.6 million (i.e., $95.6 million + $21 million) for all coal costs. The Board notes that past customers received an insurance benefit from the excess coal.

The Board notes TransAlta's assessment that the outside coal is in excess of the requirements of regulated generation. However, the Board is not persuaded that current 1999/2000 customers should bear the full burden of the costs of the outside excess coal. Further, the Board does not accept, as appropriate, that all the costs of the excess outside coal should be borne by customers without any market determination of the potential value of the coal rights.

The Board, in the absence of a market auction test to determine value, is unable to determine the appropriate costs to be written off. Accordingly, the Board denies the request to write off the $9.6 million costs (i.e., $30.6 million - $21 million) as TransAlta has proposed. The Board directs TransAlta, in its refiling, to remove the proposed $9.6 million amortization of the costs of excess outside coal rights from the test years.

The Board has stated above that it is not reviewing the original decision that allowed this asset into TransAlta's rate base. Consequently, the Board considers these assets to be no different than other GENCO assets which are required to be dealt with through the IAT/PPA process. The Board notes that the EU Act provides for this process pursuant to sections 45.4(6) and 45.5(2)(c).

On the other hand, if TransAlta were to dispose of these assets in the 1999-2000 period, the Board could deal with the resulting financial impact of the resulting gain or loss. The Board notes there are a variety of mechanisms that TransAlta could use that would result in a disposition during the 1999-2000 time period. In this regard, the Board has considered the suggestion of ENMAX that the excess coal rights should be transferred to the TA and entitled DISCOs. The Board considers that none of these parties are likely to develop these properties themselves. Through the transfer process proposed, the ownership of the coal rights would be split amongst many parties of differing financial interests and abilities. Ultimately, the Board believes that the value of these rights would be reduced. Accordingly, the Board is not persuaded that the ENMAX suggestion is practical.

[545] TransAlta Reply, p.41

The Board does, however, recognize that there may be some complexity in the appropriate treatment of these assets if they are sold or otherwise disposed of at some time after 1 January 2001. Accordingly, the Board is prepared to give TransAlta some additional flexibility in dealing with this issue if the transaction can be assured to occur in the 1999-2000 time period.

The Board has considered that there are some options that could result in TransAlta selling or disposing of its interests in the 1999-2000 time period other than the ENMAX proposal that the Board has rejected.

The Board would accept an irrevocable commitment from TransAlta at the time of its refiling to dispose of its interests in excess outside coal rights prior to 31 December 2000. At the same time, the Board will allow TransAlta to incorporate in its refiling the financial treatment as discussed below in this section of the Decision. This financial treatment would be based on the following:

- Given the circumstances of a large $30.6 million write off, the Board would accept TransAlta's proposal to apply the $21 million credit from economy energy sales against the $30.6 million of excess coal costs. Accordingly, the Board agrees that $9.6 million is the net cost that will be considered in dealing with excess outside coal costs.
- If the coal rights are disposed of at zero value to the Province of Alberta as a proxy for Alberta electric consumers, TransAlta could include an amortization amount of $436,364 (i.e., $9.6 million/22 years) for each of 1999 and 2000. For the time period beyond 1 January 2001, the entire remaining amount of $8.73 million (i.e., $9.6 million less 1999/2000 amortization of $0.87 million) would be approved by the Board for recovery from the Balancing Pool over the period 2001 to 2020.
- If TransAlta, prior to 31 December 2000, sells with the approval of the Board, all its rights and interests in the excess outside coal rights to an unrelated arms length third party, the annual recovery from the Balancing Pool after 1 January 2001 would be adjusted. (The net proceeds of the sale would adjust the remaining $8.73 million amortization to be collected from the Balancing Pool and the annual payments from the Balancing Pool proportionately.)

Accordingly, the Board directs TransAlta, in its refiling, to make a choice of one of the following options and to advise the Board at the time of refiling which of the four options it chooses:

- Option 1: Retain the current regulatory treatment for the period 1999-2000 and deal with the post 1 January 2001 period within the IAT and the PPA process. The Board directs, TransAlta, in its refiling, to reflect the same regulatory treatment on these assets in 1999 and 2000 as was in place during 1998.
- Option 2: Commit to transfer the excess coal rights to a non-regulated affiliate of TransAlta at a transfer price of $9.6 million prior to 31 December 2000. The Board directs TransAlta, in its refiling, to remove the $9.6 million from rate base effective

1 January 1999. The Board directs TransAlta, under Option 2, to transfer the excess outside coal rights to an unregulated affiliate prior to 31 December 2000.

- Option 3: Commit to gift the excess outside coal rights at no cost to the Province of Alberta as a proxy for Alberta electric consumers by 31 December 2000. The Board directs TransAlta, in its refiling, to include an amortization amount of $436,364 (i.e., $9.6 million/22 years) for each of 1999 and 2000. If Option 3 is attempted and can not be achieved, the Board would expect TransAlta to apply for an adjustment to the regulatory treatment approved in this Decision.
- Option 4: Commit to sell all rights and interests to an unrelated arms-length third party following a suitable auction process. The Board directs TransAlta, in its refiling, to include an amortization amount of $436,364 (i.e., $9.6 million/22 years) for each of 1999 and 2000. If Option 4 is attempted, and is either not successful or the transaction is not acceptable to the Board when approval for the actual disposition is applied for, then Option 3 would be acceptable to the Board. If Option 4 is successful, the Board, after consideration of an application by TransAlta, will approve an appropriate amount for net proceeds (after sale expenses). The Board will adjust the remaining $8.73 million amortization to be collected from the Balancing Pool and the annual payments from the Balancing Pool proportionately.

Under Option 3 or 4, the Board considers that the costs should be written off over the 22-year period 1999 to 2020. The costs for 1999 and 2000 will be included in TransAlta's reservation price. The costs (or benefits) for 2001 to 2020 will be recovered from the Balancing Pool. The entire remaining amount (i.e., $9.6 million less 1999/2000 amortization of $0.87 million less any net sale proceeds, after sale expenses) is approved for recovery from the Balancing Pool over the period 2001 to 2020. TransAlta needs to formalize the recovery from the Balancing Pool by applying to the Board in early 2001 for approval to be paid from the Balancing Pool.

(B) Excess Highvale Coal (Westmin 82 Agreement)

The Westmin 82 Agreement is a royalty agreement that was signed in 1982 for 40 years. It requires an annual payment, and for that annual payment, approximately 1.5 million tonnes of coal is purchased.

In completing the long term planning for the Highvale mine for the plant lives as described in Decision U97065, TransAlta has determined that 4.03 million tonnes of the Westmin coal acquired to date will be in excess of the requirements of the plants. The cost of this coal has been determined to be $4 million that has been paid for and is in a capital account but has not been expensed to customers. TransAlta proposes to recover this amount from customers by way of a $2 million charge in each of the years 1999 and 2000.

Position of the FIRM Customers

Over the years TransAlta purchased the rights to coal at the Highvale mine from various parties to ensure an adequate supply exists for the Sundance and Keephills generating stations projected lives and also for potential additional future generating units. In this process TransAlta now claims it has purchased the right to more coal than it needs ("excess coal"). TransAlta claims this coal purchase strategy has kept the cost of electric energy lower since it has enabled TransAlta to negotiate for lower prices from the coal lease owners.[546] It has in effect been a form of "insurance."[547]

As a result of the industry restructuring process TransAlta now feels a portion of the 44.264 million tonnes of coal it has the rights to and must pay for at Highvale is not required. TransAlta estimates only 40.234 million tonnes will be required to the end of 2020 according to the PPA plan.[548] The difference, 4.03 million tonnes worth an estimated $4.012 million, is now considered to be a useless asset which TransAlta proposed to have customers pay for in the current test period whilst TransAlta still retains ownership.[549]

TransAlta claims the primary reason for not being able to use this coal is "due to normal mining set setback from physical structures such as Beaver Creek, Highway 759 and the Seba Beach Highway. The secondary reason is a portion of the coal reserve is in a very high strip ratio area which makes it uneconomic."[550]

TransAlta's claim that the cost of this coal should be recovered from ratepayers is highly suspect. The coal cannot be valuable insurance at the same time as it is either unrecoverable because of setbacks from roads and creeks or is too expensive to recover. TransAlta's claims cannot all be true at once.

If the coal is unrecoverable due to normal mining setbacks, the FIRM Customers submitted TransAlta was aware setbacks from creeks and highways would be required in the normal course of doing business at the time it negotiated the lease. It should not have established a take-or-pay obligation if there was a significant question whether it could actually mine the coal for which it had to pay. The prudence of paying for a commodity that cannot be recovered is highly questionable. To our knowledge TransAlta never previously informed the Board this coal could not be recovered. Therefore, we are here in this case with our first indication TransAlta made a mistake decades ago. It entered into a commercial transaction of questionable prudence, obligating itself to pay for coal it claims cannot be mined. TransAlta, which presumably knew of its error for many years, never told anyone about it until now.

---

[546] Tr. p.1836
[547] Tr. p.1834
[548] TransAlta Evidence, Section 2.5.2; Tr. p.2799
[549] Tr. p.1831
[550] CCA.TAU-19

Those excess coal obligations were never "used or required to be used" if we believe TransAlta's explanation today, because they are too close to roads and creeks to ever be used. They are not conventional stranded assets whose market value has been impaired by changes in regulation. They either were never useful or have been known not to be useful for decades for reasons completely unrelated to deregulation. They therefore should not be recovered from ratepayers.

The FIRM Customers again questioned: "why now?" The answer again appears to be because of industry restructuring. This is a situation where TransAlta feels it is more appropriate to be paid up-front for its estimate of coal it may not be able to mine or may be less economic to mine. The FIRM Customers submitted "Another asset or apparent asset going up in smoke before our eyes."[551] It would appear industry re-structuring is being used as the basis for reducing TransAlta's risk of recovering these expenditures.

In conclusion, the FIRM Customers recommended that the forecast $4.012 million cost for excess or uneconomic coal TransAlta estimates may not be used in the future should not be expensed over 1999 and 2000. This coal either has potential significant value or should have been factored into the purchase and costing by TransAlta from the beginning to reduce the take or pay amount. It should not be treated as a stranded asset. The proposed $2 million annual expense should be disallowed for 1999 and 2000 and the costs removed from rate base.

Position of ENMAX

TransAlta estimated that at the end of 1998 it will have 4.030 million tonnes of coal valued at $4.012 million purchased under a take or pay agreement that will not be used in the foreseeable future. TransAlta now proposes to write off these costs at $2 million per year in 1999 and 2000. TransAlta acknowledged that this write off was driven by the PPA process.[552] In essence this write off results in current customers paying for the new industry framework.[553]

In CCA.TAU-19(a)(iii), TransAlta acknowledged, "The amount of non-unitized Westmin 82 purchases capitalized to date is $69.5 million, $25.4 million of which has been amortized." During cross-examination, TransAlta confirmed the Westmin 82 leases had been included in rate base in prior years[554] and that TransAlta would retain ownership of these coal rights for future use.[555]

It is curious that TransAlta provided no evidence to justify the quantification of its estimated write-offs. Even if some of the coal reserves were not to be used, there is no way to determine whether the amount of the write-offs are reasonable or whether some of that coal would be used if the estimates were understated. Load growth, demand, competition for customers, unit

[551] FIRM Customers Argument, p.182
[552] Tr. p.2372
[553] Tr. p.2368
[554] Tr. p.1833-1834
[555] Tr. p.1830-1831, p.2279

performance, and burn rates are just a few of the variables which could be very different than those contemplated in TransAlta's estimate. As the sensitivities to numerous economic factors have not been demonstrated or tested, the estimates have no basis for acceptance. Given the above, TransAlta's request amounts to a flagrant junking of valuable customer supported assets in favour of a select set of customers after the year 2000.

Under TransAlta's scenario it would be entitled to use or sell the coal rights should it be determined that they are required, or have, value some time in the future. There is no provision to deal with what would be a blatant mismatch of costs and benefits between generations of customers.

Despite the PPA process being the driving force behind this write off, TransAlta did not include the amounts in their PPA proposal or make any provision for such inclusion. TransAlta has simply assumed that the Board will approve the requested write off.[556] This is notwithstanding section 45.4(6) of the EU Act. Section 45.4(6) of EU Act requires TransAlta to include these coal rights in their proposal to the IAT. Section 45.5(2)(c) requires the IAT to determine the reasonable costs for these coal rights and section 45.96(6) allows for the costs to be paid out of the Balancing Pool.

It is ENMAX's position that the intent of section 45.4(6) was to have all stranded costs associated with coal rights or any other property transferred to the PPA proposal. It is the PPA process that is causing this asset to become stranded; therefore it is appropriate to recover the cost of the stranded asset over the effective term of the PPA process i.e. 2001 to 2020. ENMAX submitted that TransAlta is premature in writing off these capitalized coal rights.

Consistent with ENMAX's recommendation dealing with other stranded coal rights these Westmin 82 coal rights purchased prior to 1999 should remain capitalized in 1999/2000, should be included in the IAT proposal, and should be amortized from 2001 to 2020 consistent with the legislation. In the alternative, if TransAlta has lost the opportunity to include costs in the IAT process, the Westmin 82 coal rights purchased prior to 1999 should be transferred to the DISCOs and the TA in proportion to their reservation percentages. It then becomes the responsibility of the DISCOs and the TA to determine if the coal rights should be retained for future benefit or sold.

Position of LE/RD

With respect to the recovery of the value of the Highvale coal excess to the operational requirements of the generating units over the regulated life of those units, LE/RD see no compelling argument supporting an accelerated recovery of these sums from 1999/2000 customers. The 1999/2000 customers benefit no more or less than future customers from the excess coal. The coal was purchased for all customers and any excess amount should be

[556] Tr. p.2278

amortized over the regulated life of the mine. TransAlta conceded that this was an option and that the decision made was again driven by the PPA process.[557]

Position of TransAlta

ENMAX recommended that the Westmin Coal rights purchased prior to 1999 should remain capitalized in 1999/2000, should be included in the IAT proposal and should be amortized from 2001 to 2020. Similarly, LE/RD suggest that these coal rights be amortized over the period 2001 to 2020. With respect to the $2 million per year annual expense for coal that will not be used in the foreseeable future, the FIRM Customers argue that these also should be disallowed for 1999 and 2000, and the costs removed from rate base.

As noted in section 2.5.2 of the Application and CCA.TAU-19, TransAlta customers have and will continue to benefit from this Westmin 82 contract by having a secure, flexible and low cost supply of fuel throughout the life of the thermal plants. Mr. Clark stated:

> I think certainly the strategy that TransAlta had on coal rights has been a major benefit to TransAlta customers, and we have done some benchmarking studies recently that show us to be, if not the lowest cost producer in the northwest or North America, certainly one of the lowest, and I believe that that – our coal strategy at the time has really helped us to be there.[558]

Mr. Way further stated:

> ...the insurance policy we signed was for a number of years, and it did serve the customers well for a whole number of years. But the need for that particular insurance has gone away... But I think the customers, the benefits of that insurance do show up in, as Mr. Clark said, in the low cost that the customers have enjoyed over the years. But the situation has now changed where that particular insurance is no longer required, and yet the premiums for the policy have not been fully costed.[559]

Accordingly, TransAlta submitted that its proposed method of recovering the excess coal costs is reasonable and should be approved.

Board Findings

The Board agrees with the observation of the FIRM Customers:

[557] Tr. p.2372
[558] Tr. p.1836
[559] Tr. p.1837

> The coal can't be valuable insurance at the same time as it is either unrecoverable because of setbacks from roads and creeks or is too expensive to recover. TransAlta's claims cannot all be true at once.[560]

The Board is concerned in the light of the new evidence filed by TransAlta, that all or a portion of the excess coal would not have met the rate base test of "used or required to be used." Further, a question of prudence arises when a take-or-pay obligation is entered into if there is a significant question whether TransAlta can actually mine the coal for which it has to pay. The Board recognizes that there is a certain amount of "overhead" (i.e. not mineable due to setbacks, roads, etc) associated with the purchase of coal assets. The Board notes that the excess coal amounts to approximately 9% of the total tonnage associated with the Westmin 82 lease. The Board considers that this is not an unreasonable amount of "overhead" and accordingly will not disturb the past rate base treatment.

However, if the excess coal is true "overhead," it would be appropriate to allocate the costs over the mineable coal. The Board does not consider it appropriate for overhead to be deemed as "excess" with the mineable coal reserved for existing regulated and possible future unregulated generating units.

Under these circumstances, the Board is not persuaded that current 1999/2000 customers should bear the full burden of the costs of the excess coal. Accordingly, the Board denies TransAlta's request to amortize the $4.012 million during the test years and retain the Westmin coal rights associated with the excess coal.

The Board directs TransAlta, in its refiling, to remove the $4.012 million Excess Highvale Coal amortization from each of the test years.

The Board considers that the $4.012 million capital costs should be amortized over the 22-year period 1999 to 2020. The costs for 1999 and 2000 will be included in TransAlta's reservation price. The costs (or benefits) for 2001 to 2020 will be recovered from the Balancing Pool. Accordingly, the Board directs TransAlta, in its refiling, to include an amortization amount of $182,364 (i.e. $4.012 million/22 years) for each of 1999 and 2000. The Board approves the recovery of the remaining amount of $3.64 million (i.e. $4.012 million less 1999/2000 amortization of $0.364 million) from the Balancing Pool over the period 2001 to 2020.

(C) Westmin 82 Take-or-Pay (1999 and 2000)

TransAlta is required by contractual obligations to pay $3.93 million in 1999 and $4.25 million in 2000 with respect to the Westmin 82 contract. TransAlta is proposing to expense these annual payments because the coal is in excess of the plant requirements.

[560] FIRM Customers Argument p.181

TransAlta stated in Section 2.5.2 of the Application and CCA.TAU-19, that TransAlta customers have and will continue to benefit from this Westmin 82 coal contract by having a secure, flexible and low cost supply of fuel throughout the life of the thermal power plants. TransAlta's cost of fuel continues to be one of the lowest in North America.[561] Accordingly, TransAlta submitted that its proposed method of recovering the excess coal costs is reasonable and should be approved.

Position of the FIRM Customers

In 1982, TransAlta signed a long term, take or pay, lease agreement with Westmin Resources for the right to mine certain coal leases.[562] The costs of the take or pay agreement have been capitalized each year since 1982. As coal is mined from the Westmin leases, the proportionate amount of rate base is amortized into the revenue requirement as an expense. The forecast take-or-pay amounts for 1999 and 2000 are $3.93 and $4.25 million, respectively. TransAlta now plans to expense the annual take or pay expenditures for these leases as it does not believe the additional coal purchased will be used in the foreseeable future.[563]

The FIRM Customers questioned the prudence of TransAlta's decisions with these leases and why they would suddenly want to start expensing them. The answer to the sudden write off appears to relate to the restructuring of the industry. This is a situation where TransAlta feels it is more appropriate to be paid up-front for its estimate of unneeded or stranded take or pay coal at Westmin, than take its chances of using the coal under the PPA process or in the unregulated world. It would appear industry re-structuring is being used as the basis for reducing TransAlta's risk of recovering these expenditures.

The FIRM Customers also questioned why TransAlta should maintain ownership of this asset if the annual take or pay expenditures are now to be written off as current expenditures. The FIRM Customers believed the Board should consider:

- The full amount of coal from the Westmin 82 leases could be required before 2020. During the next 22 years mine plans could change resulting in the requirement to mine this coal;[564]
- The existing generation at Sundance and, especially, the younger Keephills units could be in production past 2020 and use this coal; and[565]
- The potential for capacity increases and re-powering options at these existing plants, the Westmin 82 coal could be used for the production of electric energy that is outside the PPAs (excess energy or loose juice) prior to 2020.

[561] Tr. p.1836
[562] Tr. p.1866
[563] CCA.TAU-19
[564] Tr. p.1831, l.19
[565] Tr. p.1831, l.19

TransAlta is asking customers to pay on a current basis for an asset that could have considerable value to it at some point in the future.

The FIRM Customers submitted the proposed change in accounting treatment, to expense these costs instead of capitalize them, is wholly inappropriate, especially at this juncture of the development of the industry. Further to allow TransAlta to take over these coal leases at no cost will result in a competitive advantage relative to other potential generators entering the Alberta market.

Based on the foregoing, the FIRM Customers recommend the forecast take or pay costs for the Westmin 82 coal leases for 1999 and 2000 of $3.93 and $4.25 million, respectively, be removed from TransAlta's operating expense account. These payments should be disallowed on the basis of the prudence of management decisions to lock into take or pay contracts suddenly deemed to have no value.

Position of ENMAX

In Section 2.5.2 of its Application, TransAlta states:

> In addition, TransAlta is committed to additional annual non-unitized purchases, by a take or pay contract. As this coal will not be used in the foreseeable future these annual expenditures, capitalized annually to date and expensed as mined, will be expensed as paid in the future. The amounts expensed in 1999 and 2000 will be $ 3.93 and $ 4.25 million respectively.

These amounts are, in essence, royalty amounts.[566]

Under cross-examination TransAlta confirmed that these non-unitized purchases were the Westmin 82 annual payments shown on ENMAX.TAU-43(a) except they were "the 1999 and 2000 version."[567] TransAlta also confirmed that these annual payments were included in their PPA proposal sent to the IAT.[568] The costs of these surplus Westmin 82 coal rights from 2001 onwards will be included in the PPA proposals and expensed over the effective term as required by the legislation. TransAlta acknowledged this change is being driven by the PPA process.[569]

It is ENMAX's position that the intent of section 45.4(6) was to have all stranded costs associated with coal rights or any other property transferred to the PPA proposal. It is the PPA process that is causing this asset to become stranded; therefore it is appropriate to recover the cost of the stranded asset over the effective term of the PPA process i.e. 2001 to 2020. ENMAX

[566] Tr. p.2374
[567] Tr. p.1819
[568] Tr. p.1819
[569] Tr. p.2373

submitted that TransAlta was premature in changing its accounting treatment in 1999 to expense annual payments as paid rather than being capitalized annually and expensed as mined.

Consistent with ENMAX's recommendation dealing with other stranded coal rights, these Westmin 82 coal payments for 1999 and 2000 should be capitalized, should be included in the IAT proposal, and should be amortized from 2001 to 2020 consistent with the legislation. In the alternative, if TransAlta has lost the opportunity to include these costs in the IAT process, the coal rights should be transferred to the DISCOs and the TA, in proportion to their reservation percentages. It then becomes the responsibility of the DISCOs and the TA to determine if the coal rights should be retained for future benefit or sold.

Position of LE/RD

LE/RD submitted that there does not appear to be any compelling reason to justify a change in the existing policy of capitalizing Westmin 82 payments until the coal is actually required. This is another change that TransAlta proposes to put in place because of the PPA process.[570]

LE/RD submitted that until the coal is actually mined and used, it is merely an investment in future generation production. LE/RD contended that, in TransAlta's application, there are a number of costs which are not appropriately matched to benefiting customers. LE/RD see no reason to create another one.

Position of TransAlta

For the Westmin coal rights payments in 1999/2000, ENMAX recommends that they be capitalized, then amortized from 2001 to 2020. Similarly, LE/RD suggest that these coal rights be amortized over the period 2001 to 2020. Finally, the FIRM Customers recommend that the $3.93 and $4.25 million respectively be removed from TransAlta's operating expense account and that these payments be disallowed.

TransAlta submitted that its proposed method of recovering the excess coal costs is reasonable and should be approved for the same reasons as set out in the previous section Excess Highvale Coal (Westmin 82 Agreement).

Board Findings

The Board is not persuaded that there need be any change to the existing policy of capitalizing Westmin 82 payments until the coal is actually required. The Board notes that TransAlta included the Westmin 82 payments beyond 1 January 2001 in the PPAs submitted to the IAT.

The Board accepts TransAlta's assessment that the 1999 and 2000 payments pursuant to the Westmin 82 lease are in excess of requirements for regulated generation. However, for reasons given in the previous section (Excess Highvale Coal (Westmin 82 Agreement)), the Board is not

[570] Tr. p.2373

persuaded that current 1999/2000 customers should bear the full burden of the costs of the excess coal. Accordingly, the Board denies TransAlta's request to expense the $3.93 million in 1999 and the $4.25 million in 2000 and retain the Westmin 82 coal rights associated with the excess coal.

The Board directs TransAlta, in its refiling, to remove the requested Westmin 82 Take-or-Pay amortization of $3.93 million in 1999 and $4.25 million in 2000.

The Board considers that the capital costs should be amortized over the 22-year period 1999 to 2020. The costs for 1999 and 2000 will be included in TransAlta's reservation price. The costs (or benefits) for 2001 to 2020 will be recovered from the Balancing Pool.

Accordingly, the Board directs TransAlta, in its refiling to include an amortization amount of $178,636 (i.e. $3.93 million/22 years) for 1999 and $381,017 ($178,636 + $202,381 (i.e. $4.25 million/21 years)) for 2000. The Board approves the recovery of the remaining amount of $7.62 million (i.e. $3.93 million + $4.25 million-1999/2000 amortization of $0.56 million) from the Balancing Pool over the period 2001 to 2020.

(D) Coal Reclamation Costs

Coal reclamation costs are divided into levelized and liability reclamation costs.

Levelized reclamation costs refer to ongoing reclamation costs incurred throughout the life of the mine. The levelized reclamation reserve comprises the ongoing operating expense component of the reclamation reserve and is intended to stabilize the revenue requirements which otherwise would fluctuate widely as a result of the need to advance certain reclamation activities at a pace very different than the advancement of mining. The levelized reserve also accommodates changes to the regulatory reclamation standards such as topsoil, subsoil salvage and replacement depths, by spreading any resulting incremental cost savings or expenditures over a longer period of time.

Liability reclamation costs refer to reclamation costs incurred at the end of the life of the mine. The reclamation liability reserve was established to ensure adequate funding is available subsequent to the completion of mining to conduct final land reclamation and site decommissioning. This reserve can be compared to the salvage costs associated with capital assets; however, it is for reclamation of the mine pits created through normal operations.

Both the levelized reclamation reserve and the liability reclamation reserve are key components in a process developed to ensure that today's electricity customers pay a fair share of the ongoing and future reclamation costs and that the company is left whole at the end of the mine life.

TransAlta's annualized costs for the liability and levelized reclamation components for the Highvale and Whitewood mines are as follows:

2. GENCO
(c) Non-Cash Operating Expense

			$ millions		
Highvale Mine	**1996**	**1997**	**1998**	**1999**	**2000**
Liability	(1.24)	(1.23)	(1.24)	1.44	1.44
Levelized	3.24	3.43	3.23	12.92	12.98
Total	**2.00**	**2.20**	**1.99**	**14.36**	**14.42**

Whitewood Mine	**1996**	**1997**	**1998**	**1999**	**2000**
Liability	0.16	0.16	0.16	0.14	0.13
Levelized	0.75	0.77	0.74	1.26	1.22
Total	**0.91**	**0.93**	**0.90**	**1.40**	**1.35**

Source: TransAlta Evidence, Tab 2.6, p.1-2

Highvale Mine

Norwest Mine Services Ltd. was retained by TransAlta to review past and future reclamation costs at the Highvale Mine. TransAlta requested the review as a result of the growing discrepancy between the actual reclamation costs being incurred at the mine and what is being collected through rates. The review was conducted on the reclamation liability that currently faces the corporation and that which will occur over the remaining approved life of the generating units. TransAlta, in its Application, included the results of a review in a report entitled "Highvale Mine Reclamation Costing Review" prepared by Norwest Mine Services Ltd. TransAlta submitted that the costs and volumes of mine material described in the report were for the most part based on many years of experience at the Highvale Mine, and are representative of what can be expected in the future.

The report concluded that there was a large and increasing unfunded reclamation liability that exists at this mine which is not being accrued. The costs forecast for 1999 and 2000 reflect the review conducted for the test years and the PPA period (i.e. the 1999 to 2020 reclamation plan). The report proposed increases to both the levelized expense and the liability expense.

The increase in the levelized expense from the 1998 rate of $0.35/tonne to the proposed 1999/2000 rate of $1.03/tonne was claimed to be due to the following:

- Future reclamation work. A revised estimate of the reclamation costs associated with coal to be delivered in the future for regulated units in the amount of $113 million ($105.7 million + $8.3 million expit costs from past disturbances, Table 6.2 of Norwest report) over 245 million tonnes of coal ($0.46/tonne).
- Past reclamation work. A backlog of reclamation costs associated with past disturbances in the amount of $14.4 million ($20.3 million in Table 6.2 of Norwest report less $5.9 reserve balance) proposed to be collected over 1999 and 2000 over 25.2 million tonnes of coal ($0.57/tonne).

TransAlta applied to recover the past deficiency of $14.4 million at a rate of $7.2 million in each of the years 1999 and 2000. The $7.2 million per year is included in the levelized amounts of $12.92 million for 1999 and $12.98 million for 2000 shown in the above Highvale Mine table.

TransAlta stated that it is attempting to match the costs of delivering coal to those customers who benefit from the electricity being consumed.[571] Only the direct costs of $14.4 million have been included in the backlog over 1999 and 2000; the expit supervision, management and other overhead costs of $8.3 million associated with the backlogged reclamation work have been spread over the remaining life of the mine. This was considered to be a reasonable compromise between expensing the total costs over the next two years and charging future customers the entire amount.

The increase in the liability expense from 1998 to 1999/2000 was claimed to be due to the following:

- 1998 is the last year of the 5 year reduction in the liability reserve that had been implemented to reduce the balance for the reclamation of one final pit, rather than to cover the costs associated with reclamation of all of the mine pits. In the earlier reclamation plan, these costs had been included in the ongoing or levelized portion of the reclamation forecast because they were planned to be decommissioned and reclaimed though the operating life of the mine. In the revised reclamation plan, the costs to decommission and reclaim each pit have been included in the liability forecast. This was done to ensure that the fixed costs associated with end-of-mine life reclamation and the ongoing variable costs are separated and accounted for individually.
- 1999 and 2000 includes the result of the addition of another mine pit (pit 08) and the associated end-of-mine life reclamation and decommissioning costs associated with this pit. Pit 08 was required as a result of the AEUB directed life extensions for the generating units at the Sundance and Keephills plants. Additional final reclamation costs were also included to cover the costs associated with replacement of County Roads across the reclaimed lands. This requirement was identified as a result of completion of the Highvale Land Use Plan recently completed by the local municipality.
- 1999 and 2000 also includes costs not previously identified in previous long-range plans. These include pre-strip bench stabilization, end cut stream channel erosion protection, coal haul ramp reclamation through pre-strip dumps, and the Beaver Creek bridge replacement.

The total cost for end-of-mine life reclamation is $28,730,166. The liability reserve balance sits at $547,499. Remaining liability cost is therefore $28,182,667 or $0.12/t (Table 7.2 in Nor-west report)

[571] BR.TAU-26(b)

Whitewood Mine

TransAlta stated that the levelized expense increase from 1998 to 1999/2000 is due to the following:

- An increase in reclamation unit price expense rate from $0.28/t to $0.43/t due to the inclusion of forecast reclamation costs for decommissioning and reclaiming coal haul roads and complete reclamation of the main ash dump. These forecast costs had not previously been included in the reclamation forecast and were added as they are now recognized as being required to complete the total amount of reclamation work required over the remaining life of the Whitewood mine
- An increase in coal burn of 0.5 million tonnes.

TransAlta stated that the liability expense decreased from 1998 to 1999/2000 due to the following:

- Lower forecast costs to fully decommission and reclaim the final end cut after all coal deliveries are completed in year 2003. The previous estimate of $2.6 million has been reduced to $2.4 million.

Sheerness

TransAlta's share of reclamation costs at Sheerness were forecast to be $0.4 million in each of 1999 and 2000 compared to a 1998 forecast of $1.0 million and a 1997 actual of $0.6 million.

Position of ENMAX

Tab 2.6.1 of TransAlta's Application relates to the Highvale mine reclamation costs and shows the reclamation costs for 1996 based on the plant reclamation costs as they were known at that time. At that time, all the liability reserve was in the last remaining pit.[572] The change proposed in this application is that the pits will be covered by the liability reserve as they are abandoned. TransAlta confirmed that the Highvale coal resources will not be exhausted until after the end of the longest base life in 2023.[573] TransAlta suggested that the answer to whether there will still be coal being mined is irrelevant as a result of the GUR. While the impact of GUR is arguable, the Board is charged with setting just and reasonable rates in 1999/2000 which includes determining the extent to which reclamation costs should be included in the revenue requirement. To this extent the question of whether there will still be coal mined after 2023 is relevant since the GUR does not mandate that all perceived reclamation costs be included in the pre PPA costs.

In 1996 the liability reserve was for one final mine pit which would be a cost incurred when all the coal was exhausted.[574] TransAlta suggests the proposed liability reserve is a reallocation of

[572] Tr. p.1729
[573] Tr. p.1730
[574] Tr. p.1733

costs and not an increase. However, the costs in 1999/2000 have increased significantly.[575] In the PPA base plan the costs to decommission and reclaim the individual pits are included in the liability forecast which is $28 million higher than under the previous plan.[576] Although the PPAs will not come into effect until 2001, and will be under the direction of the IAT, TransAlta is seeking the change now.[577] Part of the increase in liability reserve is a "catch up" for past unclaimed costs of reclamation; costs which were not recognized by TransAlta until its mining consultant suggested they should be recovered.[578] This explains much of the forecast unit rate increase in reclamation costs from $.35 to $1.03/tonne in 1999 as it accounts for $.57/tonne of the increase (based on the amount being amortized over the coal mined in 1999/2000). The revised current reclamation cost of $.46/tonne is based on amortizing the costs of future reclamation over the 244 million tonnes remaining at Highvale.[579]

During cross-examination TransAlta agreed that:

- the cost of backlogged reclamation does not benefit future customers and it would not be fair to charge future customers;
- the cost of backlogged reclamation does not benefit current customers and current customers should pay the same amount as past and future customers;
- the current estimate of future reclamation costs is $0.46/tonne and is being charged the same to current as future customers; and
- reclamation estimates will change in the future if there are future changes in escalation rates or other factors.[580]

The volatility in reclamation costs estimates is evidenced by the changes since 1996 when there was a credit to the reclamation reserve. ENMAX notes that TransAlta, under its new methodology, has identified a deficiency in its accumulated reclamation reserve. It was identified through a process similar to those used to identify depreciation deficiencies. In the case of depreciation a deficiency is amortized over the remaining life of the asset. Similarly, the deficiency in the reclamation reserve should be amortized over the remaining life of the coal at Highvale.

The IAT will be required to make determinations for the PPAs and the Board should exercise caution in determining future reclamation costs for this GTA. TransAlta suggested the technology of moving dirt does not change much[581] but the advent of ever-larger machines over

[575] Tr. p.1734
[576] Tr. p.1735
[577] Tr. p.1736
[578] Tr. p.1753
[579] Tr. p.1757
[580] Tr. p.1759-1761
[581] Tr. p.1762

the past years suggests this is not accurate. ENMAX recommended that all the costs of reclamation be amortized over the remaining 244 million tonnes of coal at Highvale.

Position of the FIRM Customers

TransAlta stated there is a large, unfunded reclamation liability associated with the Highvale mine. It is forecast to be incurred over the remaining Board approved life of the generating units. The 1999/2000 cost of this liability accrual "reflect the review conducted for the PPA base, 1999 to 2020 reclamation plan."[582]

TransAlta identifies two main factors causing an increase in levelized mine costs. First, $0.46/tonne is forecast "for future reclamation work associated with coal delivered in the future." Second, $0.57/tonne, or $14.4 million ($20.3 million per the Norwest Report, less the $5.9 reserve balance), resulting from "backlogged reclamation amounts over two years ($0.57/tonne or $7.13 million)."[583]

While the recovery rate of $0.46/tonne may have some merit, the FIRM Customers submit it is entirely inappropriate to collect backlogged reclamation costs over just the two test years. To do so suggests only the current customers receive the benefits of these costs. The fact TransAlta now finds itself in a deficit position, not having recovered enough from past customers, does not justify collections from just the current generation of customers.

TransAlta also acknowledges only a small portion of the $20.3 million (less the $5.9 million reserve balance) in backlogged reclamation work will be done in the test years.[584] It goes on to note most "of this catch-up will be in the future."[585] In the submission of the FIRM Customers, funding necessary to catch up with past under-collections should be matched with the way actual, or anticipated, reclamation work will be done. To that extent, all present and future customers should be assigned cost responsibility. Since TransAlta does not expect to do much of the backlogged reclamation work in the test years, customers in 1999 and 2000 should shoulder little, if any, of the $20.3 million costs. Such treatment would also be consistent with TransAlta's treatment of future reclamation work for coal inasmuch as both current and future customers are assessed this cost responsibility.[586]

TransAlta tries to justify writing off these costs during the 1999 and 2000 period by implying there are different classes of customers (i.e. old vs. new).[587] The FIRM Customers submit this approach is inconsistent with industry restructuring and the intent of the EU Act.

---

[582] TransAlta Evidence, Tab 2.6
[583] TransAlta Evidence, Tab 2.6.1.2
[584] Tr. p.3314-3315
[585] Tr. p.3315
[586] Tr. p.1761
[587] Tr. p.2365

Therefore, the FIRM Customers recommended that TransAlta be directed to provide a revised estimate of the levelized reclamation costs in its refiling. The estimate should be done on the basis the backlogged reclamation of $20.3 million amortized over the life of the generating units, consistent with the rate at which work will actually be carried out. The allocation of expit costs should also be collected over the life of the generating units.

Position of LE/RD

A major portion of the reclamation cost increase results from the recovery of the shortfall relating to past disturbance. All but the expit portion is being recovered over the 1999/2000 period. The expit portion of the cost, some $8 million, is being allocated over the remaining life of the plant.[588] LE/RD submit that it is not an unusual practice to amortize depreciation differences over the remaining life of the plant, that TransAlta is doing that with respect to the expit costs, and that they ought to do it for the remaining reclamation shortfall arising from past disturbances.

At pages 16 to 18 of its Argument, TransAlta deals with its proposal to recover certain costs associated with coal and reclamation on an accelerated basis. TransAlta presented no compelling reason why customers in the years 1999 and 2000 should pay the entire costs of the shortfall in reclamation reserve for prior disturbances.

Position of TransAlta

ENMAX, at page 36 of its argument, recommended that all deficiencies for reclamation be amortized over the remaining 244 million tonnes of coal at the Highvale Mine. LE/RD similarly recommend that the reclamation costs be amortized over the remaining lives of the plants. Finally, the FIRM Customers suggest that TransAlta be directed to provide a revised estimate of the levelized reclamation costs on the basis that the backlogged reclamation be amortized over the life of the generating units, consistent with the rate at which work will actually be carried out.

TransAlta provided a detailed analysis of the projected costs of the reclamation which was based on years of experience at the Highvale Mine and is representative of what TransAlta expects to see in the future. TransAlta stated that:

> The costs associated with reclamation of areas from which coal was delivered in the past ($20.3 million less the forecast balance in the reserve contributed by past customers of $5.9 million, Table 6.2 in Norwest Report) has been allocated to all of the past customers who have benefited from the coal delivered in the past. In order to match costs of the coal with the customers that benefited from that coal and reduce the length of time that future customers are paying for benefits obtained by past customers, TransAlta has allocated the backlog over the coal produced in 1999 and 2000.[589]

[588] Exhibit 58, revised response to SPPA.TAU.4 (f)
[589] BR.TAU-26(a)(b)

In addition, Mr. Clark stated: "Well, we believe that the past customers have benefited from that, and it seems that it would not be fair for the future customers to pay for the benefits that were received from past customers."[590] Further, Mr. Clark stated:

> We collect the reclamation required cost on a per tonne basis so that every customer gets treated the same way. So, there is a distinction between how we collect for the reclamation and put it in a reserve account and then how we do the reclamation and draw out of that reserve account. So our application has been to essentially collect the money that has to do with past reclamation, but even though we won't be able to complete it, at least we will have the funding in place to have it completed when it is required to be completed.[591]

As a result, TransAlta submits that it is appropriate to recover the deficiency in reclamation over the period of 1999/2000.

TransAlta submitted that the FIRM Customers suggestion that a revised estimate of the levelized reclamation costs be provided, on the basis that the backlogged reclamation be amortized over the life of the generating units, is entirely inappropriate. The suggestion will result in intergenerational inequities, and even creates the possibility that some reclamation costs may not be assessed until after a plant is shutdown. As a result, TransAlta submitted that the Board should dismiss the FIRM Customers' recommendation.

Board Findings

The Board has reviewed the Norwest report and considers the assumptions and results to be reasonable. Accordingly, the Board accepts, as reasonable, the future reclamation costs at the Highvale mine of $0.46/tonne.

The Board also accepts the Norwest report's current estimate of the $14.4 million deficiency in past reclamation costs for the Highvale mine. The Board notes that periodic studies of reclamation costs result in estimates of excesses or deficiencies from time to time. The Board considers that in circumstances where the estimates can change from time to time, the reclamation unit cost should be developed using total remaining reclamation costs spread over the remaining tonnage to be mined.

Accordingly, the Board directs TransAlta, in its refiling, to utilize a levelized reclamation cost of $0.524/tonne for the Highvale mine calculated as follows:

[590] Tr. p.1760
[591] Tr. p.3315

• Backlogged reclamation costs	$20.3 million
• Less existing reclamation reserve balance	$5.9 million
• Equals deficiency in past reclamation costs	$14.4 million
• Plus future reclamation costs	$105.7 million
• Plus expit costs from past disturbances	$8.3 million
• Equals net remaining reclamation costs	$128.4 million
• Divided by remaining tonnage to be mined	245 million tonnes
• Equals unit reclamation cost	$0.524/tonne

The Board notes that TransAlta's requested unit reclamation cost was $1.03/tonne which resulted in requested levelized reclamation costs of $12.92 million in 1999 and $12.98 million in 2000. Using the Board's unit reclamation cost of $0.524/tonne and forecast coal burns of 12.5 million tonnes in 1999 and 12.6 million tonnes in 2000, the Board considers the levelized reclamation costs will drop to approximately $6.55 million in 1999 and $6.60 million in 2000.[592]

The Board accepts, as reasonable, TransAlta's annualized rate of $0.12/tonne for the liability component of the Highvale mine reclamation costs for 1999 and 2000.

The Board notes that the levelized cost of $0.43/tonne at the Whitewood mine compares favorably with the $0.46/tonne at the Highvale mine determined in the Norwest report. The Board notes that based on the Whitewood annual coal burn of 2.86 million tonnes shown in FIRM-TAU 9, the liability cost works out to be $0.05/tonne. Similarly, this liability cost of $0.05/tonne compares favorably with the $0.12/tonne Highvale liability cost determined in the Norwest report. Accordingly, the Board also accepts, as reasonable, TransAlta's annualized costs for the levelized and liability components of the Whitewood mine reclamation costs for 1999 and 2000.

The Board also accepts TransAlta's 1999 and 2000 forecast of the share of the Sheerness mine reclamation costs as being reasonable considering past reclamation costs at the Sheerness mine.

(d) Income Tax

TransAlta stated that income taxes are now calculated separately for GENCO. TransAlta's prior practice was to calculate income taxes on a corporate basis and allocate the result to generation, transmission and distribution. All actual cumulative timing differences including capital cost allowance are directly assigned to each function.[593]

[592] Exhibit 58, SPPA.TAU-4(f)
[593] Application Section 6.2

2. GENCO
(d) Income Tax

For GENCO TransAlta included, in its Application, a forecast income tax of $93.7 million for 1999 and $100.1 million for 2000.[594]

Board Findings

For purposes of this Decision, the Board approves the method, set out in Part 4–TAU, 1(f), Income Tax of this Decision, to calculate the component of revenue requirement attributable to income taxes for GENCO. The Board directs TransAlta, in its refiling, to provide detailed calculations for the recalculated income taxes to GENCO using the approved method described in the section noted above.

(e) Small Power Payments

TransAlta is forecasting increases in *Small Power Research and Development Act* (SPRD Act) payments from $34.5 million in 1998 to $40.3 million (changed to $41.3 million per CCA.TAU-3) in 1999 and $40.7 million (changed to $41.4 million per CCA.TAU-3) in 2000.[595]

The SPRD Act costs were calculated for 1999 and 2000 as follows:

	($,000)	
	1999	**2000**
Allocated Energy Cost: (Allocated Energy times contract price)	$32,900	$33,542
Revenue Adjustment: (15% of Allocated Energy Cost)	4,935	5,031
Excess Energy Cost: (Excess Energy production times pool price)	3,524	2,864
Total Small Power Payment	**$41,359**	**$41,437**

The Board notes that there is no issue to be resolved respecting the calculation of the allocated energy cost. Accordingly, the Board accepts TransAlta's calculations shown in the above table for 1999 and 2000.

The Board will deal with the issues surrounding the calculation of the Revenue Adjustment and Excess Energy Cost in the following subsections.

[594] Exhibit 59

[595] TransAlta Evidence, Schedule. 2.3.2, Line 3

(1) Revenue Adjustment

The increase in forecast Small Power Payments included a provision for a revenue adjustment forecast potentially owed to producers under the Revenue Adjustment Regulation AR 358/94 (RAR). Payments under the RAR are forecast to be $4.935 million and $5.031 million for 1999 and 2000.[596]

TransAlta explained its forecast and accounting for the RAR in its filing as follows:

> Since the inception of the RAR, TransAlta has collected from customers and accrued a liability of $14 million ($3-4 m per year), while it has paid out only $2 m ($0.5m per year). The regulation allows the producers up to three years for a revenue adjustment payment. So far, only one producer (Dickson Dam) has received payment, although other producers may still apply for payment for the period from 1995. Accordingly, TransAlta has included the accrued liability in No Cost Capital.[597]

The actual amount paid under the RAR for the three years 1995, 1996 and 1997 combined was $1.537 million and TransAlta is forecasting annual payments of $500,000 for each of 1998, 1999 and 2000 for a total pay out of $3.037 million. All of these payments, actual and forecast, are to a single producer, the Dickson Dam. TransAlta's provision for RAR claims is forecast to accumulate to $25.876 million as at the end of 2000 and net of actual and forecast claims of $3 million result in a closing liability of $22.839 million. TransAlta confirmed this liability is at best, a contingent liability.[598]

Position of the FIRM Customers

The issue of concern to the FIRM Customers is how large a reserve should TransAlta be required to set up as a contingent liability owed to the producers under the RAR for revenue adjustment claims. The following are the relevant portions of the RAR that govern eligible producers entitlement to revenue adjustment claims:

> **2(1)(c)** income tax under the provincial tax Act or the federal Act in respect of the taxation year was payable and paid in full by the producer,
>
> **(d)** the producer provided an estimate in respect of the taxation year as required by section 9,
>
> **(e)** the producer
> ....

[596] Exhibit 81
[597] TransAlta Evidence, Section 2.3.3.3
[598] Exhibit 81; CCA.TAU-14(d)

(ii) provided the Government of Canada with sufficient information in respect of the year to allow such a payment to be made,

(f) the producer distributed in accordance with the *Utility Companies Income Tax Rebates Act* all the payments received by the producer under section 4 of that Act...[599]

The foregoing clearly suggests the eligible SPP must demonstrate income taxes were payable and paid in full. There is no evidence on the record in these proceedings indicating a change from the experience to date that eligible SPPs, other than Dickson Dam, are taxable or have paid taxes. As TransAlta points out they have no visibility as to whether an SPP will submit an application to the DRD.[600] The reality, as borne out by the claims to date, is that the majority of the eligible SPPs are probably not in fact taxable and have not paid any income taxes. This reality is further supported by the fact it was the SPPs that were instrumental in ensuring the RAR was enacted for their benefit and it is highly unlikely they would withhold applications for recovery of the revenue adjustment for income taxes paid to the last minute.[601] The simple fact is they do not qualify for this entitlement and no claim is likely to be made for 1996, 1997 or 1998 that is not already in front of TransAlta.

The RAR program was implemented 1 January 1995 and in section 3(2) of the RAR, the eligible SPP must apply "no later than 3 years after the end of the taxation year in respect of which it is made." With respect to this latter requirement, it is clear no further claims can be made with respect to 1995 since any claims for 1995 must have been made by the end of 1998. TransAlta has indicated it has received no additional claims for 1995.[602] The consequence of no further claims for 1995 is an over provision for expected claims of $2.6 million (total provision for liability estimated by TransAlta of $3.1 million less payment in 1995 of $0.5 million to Dickson Dam).[603] This over provision must be considered in establishing the appropriate contingent liability for 1999 and 2000.

With respect to the provision for claims accruing to the liability account for the years 1996 through to 2000, there are several factors suggesting the amount estimated by TransAlta is excessive.

First, no notification has been received by TransAlta from the Minister in charge of claims. Under section 5(2) of the RAR, the Minister is required to "notify the public Utility of the amounts of revenue adjustment payable to the contracting producer.... within 30 days after the

[599] CCA.TAU-14a
[600] Tr. p.1903
[601] Tr. p.2380
[602] Tr. p.1911
[603] Tr. p.1901; Exhibit 81–Revised FIRM.TAU-10(b)

Minister determines or re determines the amount."[604] Based on the evidence before this Board, no such notification has been received by TransAlta other than for the Dickson Dam claims.[605]

Another factor is the fact no estimates have been received by TransAlta.[606] Section 9(1) of the RAR provides:

> A contracting producer shall provide the Minister and the public Utility with ***an estimate*** of the revenue adjustment of the producer for each taxation year that includes a part of the term of the small power production contract ***whether or not an application has been made under this Regulation*** in respect of that year.[607] (emphasis added)

Section 9(2) of the RAR requires the estimate "shall be provided to the public Utility at a time specified by the public Utility and to the Minister at a time specified by the Minister." According to TransAlta it has not provided the SPPs any such specified time for provision of their estimated claims.[608] The evidence before the Board is that no estimate of the potential claims under the RAR have been provided to TransAlta by the eligible producers or the DRD. The conclusion is that the likelihood of claims beyond those of the Dickson Dam are remote and therefore it appears TransAlta is setting up a provision for potential claims where the liability is highly unlikely to actually arise.

TransAlta has established the annual RAR claims provision based on the maximum claims possible on its forecast amount eligible for the adjustment.[609] The schedule attached to the RAR provides the formula for calculation of the revenue adjustment. Essentially this formula states the adjustment is the ***lesser*** of (a) 15% of eligible revenue of the producer and (b) a factor based on the income tax for revenue adjustment purposes and the federal and provincial tax rates (this calculation provides for a revenue adjustment that is greater than the actual taxes paid).

Since TransAlta does not know the amount of income taxes paid by the SPP, it has estimated the annual provision for claims under the RAR based on 15% of the eligible revenues. TransAlta has not tried to use any probability of claims under the program to estimate the annual provision. The amounts provided for by TransAlta represent the absolute or maximum potential exposure to claims from eligible producers. If history is any indicator of potential claims it is clear TransAlta's method of accrual significantly overstates the claims and the contingent liability.

---

[604] CCA.TAU-14(a)
[605] Tr. p.1912
[606] Tr. p.1912
[607] CCA.TAU-14(a)
[608] Tr. p.1913
[609] Tr. p.1901, Exhibit 81–Revised FIRM.TAU-10(b)

2. GENCO
(e) Small Power Payments

In summary the evidence establishes the following:

- There has only been one eligible producer claim revenue adjustments since inception of the program and that producer has made a claim every year;
- SPPs are well aware of their entitlement to revenue adjustment claims under the RAR;
- Eligible SPPs have not applied for a revenue adjustment because they are not entitled to a claim;
- No further claims can be submitted with respect to 1995;
- TransAlta has not received notification from the Minister respecting any outstanding claims or estimated claims under the RAR;
- Eligible producers have not provided TransAlta, or to TransAlta's knowledge the Minister, estimates of the revenue adjustment claims they may be entitled to as required under section 9 of the RAR; and
- TransAlta's annual provision for claims is the maximum possible and is not supported by the history and even if the SPP makes an application for claim it could be subject to adjustment by the Minister. The Minister may refuse to determine the amount of the revenue adjustment or may vary the amount previously claimed.[610]

Based on the foregoing, the FIRM Customers submitted the Board should not allow the inclusion of the provision for potential payments under the RAR as part of TransAlta's fuel and purchased power costs. In view of the uncertainty of these costs ever being incurred, the FIRM Customers recommended the liability reserve only be set up when known with a reasonable degree of certainty. The FIRM Customers also recommended, based on the history of claims the probability of claims reaching the maximum provision made by TransAlta is highly unlikely. A reserve of $5 million at the end of 2000 would appear to be more than adequate to cover the claims likely to be received.

The costs under the RAR should only be recognized when incurred. To the extent revenue adjustment payments are required in the post 2000 period they should be from the Balancing Pool, as suggested by TransAlta.[611] The amounts collected from customers to the end of 1998 and not refunded to customers in 1999 and 2000 and not paid out to SPPs should also flow into the Balancing Pool at the beginning of 2001.

The Board should therefore reduce the forecast provision for revenue adjustment payments to the Small Power Producers in the test years, as follows:

[610] Subsections 4 and 8, RAR
[611] Tr. p.1919

	($000) 1999	2000
Amount of Expense per TransAlta	4,935	5,031
Net Reduction per FIRM	4,935	5,031

Source: Exhibit 81

TransAlta confirmed the amounts provided for revenue adjustment claims and not paid out were recorded as accounts payable prior to this proceeding where they are now reflected as No-Cost Capital.[612] Clearly accounts payable was an inappropriate treatment for this reserve. To the extent these forecast costs were collected by TransAlta, not paid out and received at no cost, they should be included as no cost capital. The FIRM Customers recommend the mid year balance of the accumulated amounts in the reserve be included as no cost capital.

The Board should also reduce the reserve to a balance of $5 million at the end of 2000 as detailed in the table below.

	($000)	
Cumulative Net Collections (Reserve)	**1999**	**2000**
Balance, beginning of the year	13,873	9,500
Draw down of reserve per FIRM	- 3,873	- 4,000
Payments during the year	- 500	- 500
Balance, end of the year	9,500	5,000
Mid year balance	11,687	7,250

Source: Exhibit 81

Based on the foregoing recommendations, the FIRM Customers submitted that the Board should direct that the $5 million or the balance remaining in the reserve for revenue adjustment claims at the end of the year 2000, be transferred to the Balancing Pool. Any subsequent payments required under the RAR would be from the Balancing Pool during the PPA period.

The result of these proposed adjustments is a reduction in revenue requirement of $8.808 million in 1999 and $9.031 million in 2000. The FIRM Customers recommended that the Board require these adjustments be reflected in TransAlta's refiling.

Position of ENMAX

TransAlta is seeking recovery of $41.3 million in 1999 and $41.4 million in 2000 for small power production payments. These amounts include payments for energy plus all potential liability under the RAR.[613] The RAR amounts for 1999 and 2000 are $4.935 million and $5.031 million respectively.[614] In the response to Exhibit 81–Revised FIRM.TAU.10(b), TransAlta

[612] CCA.TAU-14(e); Exhibit 81; Tr. p.1909
[613] Tr. p.1892
[614] Tr. p.1900

provided a continuity schedule for the RAR amounts since 1995 which shows that by the end of 2000 TransAlta will have collected a cumulative total of $25.1 million.

Actual payments to the end of 1997 have only been $1,537,000. The forecast payments for 1998–2000 are an additional $1.5 million. Dickson Dam has been the only claimant to date and is the only claimant forecast for the test years. TransAlta suggests it does not have "visibility" as to whether there are likely to be more claims.[615] TransAlta confirmed that the amounts collected and to be collected are included in No-Cost Capital, and as such are customer supplied capital.[616]

The response to CCA.TAU-14.1(d) outlines the conditions which must be met to qualify for RAR. They include that the producer must make an application to the Minister within three years after the end of a taxation year to be considered; the producer must have paid income tax; the producer must have distributed all payments; and the producer must supply an estimate to the Minister and the utility for each taxation year whether or not an application has been made.[617] TransAlta indicated they did not know at the time of their filing that there would not be a claim for 1995 so they did not propose to refund amounts collected in 1995. They further indicated that the DRD had not informed them of any claims and they had received no estimates of any claims from producers.[618] Section 9 of the RAR places the onus on TransAlta to collect estimates but they have not attempted to do so.[619]

TransAlta suggests the Balancing Pool could be used post 2000 to refund unclaimed collections to customers.[620] With respect, the customers should not have to wait to be refunded monies collected for RAR. The rules of the Balancing Pool are, as yet, unknown. Therefore there is a significant risk related to the treatment of customer supplied capital after 2000. TransAlta's own actual and forecast is that only $3 million of the $25.8 million it has collected will be claimed by the end of 2000[621] leaving $22.8 million of customer supplied capital at risk.

ENMAX recommended that in light of the minimal claims to date, the lack of any notification of any prospective claims or even of any estimates and TransAlta's failure to require estimates that would allow for a reasonably accurate forecast, the Board should:

- Order an immediate refund of the $2.561 million unpaid to 1995 as claimants are now out of time for 1995 claims;
- Order a refund of $11.312 million being the over collection for 1996 ($3.318 million), 1997 ($3.688 million), and 1998 ($4.306 million);

---

[615] Tr. p.1903
[616] Tr. p.1904
[617] Tr. p.1911-1912
[618] Tr. p.1912-1913
[619] Tr. p.1913
[620] Tr. p.1919
[621] Exhibit 81

- Deny the amount of $8.966 million being the forecast over collection for 1999 ($4.435 million) and 2000 ($4.531 million).

Position of LE/RD

TransAlta is accruing the maximum amount available to Small Power Producers pursuant to the provisions of the RAR affecting small power producers under the SPRD Act.[622] By the end of the year 2000, the sum of $22.5 million will have been accrued.[623] At this point, approximately $14 million has been accrued, but only $2 million has been applied for and paid out,[624] all of which has been paid to the owners of the Dickson Dam hydro units.

Pursuant to the terms of the RAR, owners are obliged to provide notice to the utility of their intention to seek payment pursuant to the regulation in the taxation year in which such payment is being sought. Such payments have been available for tax years commencing in 1995, but the only owner which has provided notice in the relevant periods is the owner of the Dickson Dam units.[625] This is notwithstanding that the Small Power Producers lobbied hard for this regulation and have made constant representations about the requirement for additional revenues.[626]

In these circumstances, LE/RD are of the view that collecting the maximum amount that would be payable if each Small Power Producer qualified for and made application for the revenues amounts to an over collection which is not justified on any review of the facts. This is especially so when the utility has no clear concept about how this money might be returned if it is found, as is likely, to be an over collection. As an alternative to the TransAlta proposal, LE/RD recommend that no collection occur at this time other than with respect to the Dickson Dam and that the matter be subject to a deferred consideration and dealt with at the end of 2000.

Position of TransAlta

LE/RD recommended that no further collection in respect of the RAR occur at this time other than for Dickson Dam, and that the disposition of the reserve be subject to a deferred consideration and dealt with at the end of 2000.

The FIRM Customers recommended that a reserve of $5 million at the end of 2000 would be adequate and that payments required in the post 2000 period be from the Balancing Pool.

ENMAX recommended that, in light of the claims to date and TransAlta's failure to require estimates, the Board should order a refund of the balance in the RAR reserve as of 31 December 1998 and should only allow forecast claims for Dickson Dam to be included in the test period

[622] Tr. p.2808-2809
[623] Tr. p.3454-3455
[624] TransAlta Evidence, Section 2.3.3.3
[625] Tr. p.2377
[626] Tr. p.2377-2381

revenue requirements. ENMAX noted that TransAlta suggested the Balancing Pool could be used post-2000 to refund unclaimed collections to customers.

ENMAX also described as "knee-jerk reactions" and "broad sweeping assumptions" proposals by TransAlta witnesses that balances in deferral and reserve accounts be dealt with by the Balancing Pool.

TransAlta submitted that a review of the evidentiary record, including the transcript references provided by ENMAX, reveals that the only proposal by TransAlta for the use of the Balancing Pool to dispose of balances in reserve accounts was with respect to the RAR reserve. Consistent with section 45.96(5) of the EU Act, TransAlta expects that RAR payments will be paid out of the Balancing Pool in the post-2000 period. Accordingly, TransAlta submitted that it would also be appropriate for any balance in the RAR reserve to be transferred to the Balancing Pool.

ENMAX's assertion that TransAlta proposed the use of the Balancing Pool to dispose of other balances in deferral or reserve accounts is erroneous and contrary to the clear evidence on the record.

ENMAX was critical of TransAlta's failure to require estimates from the Small Power Producers. As Mr. Way explained,[627] TransAlta is caught between a rock and a hard place:

> A: This is a very funny area. To some extent, small power producers have expressed their need for additional revenue countless times, endless times, and generally, we have tried to – in order to keep costs as low as possible to customers, we have tried to take every effort everywhere to keep costs under control. This is one of those areas where we seem to be caught, in my view, between a rock and a hard place.
>
> On one hand, it appears as if perhaps we by making – we are not making any efforts to go out and I would say hound these people as to when are they going to make applications, are you going to make applications.
>
> On the other hand, if we did that, I have got a feeling that customers might come back and say, why are you provoking those people to make applications? This is to spend some customer money and to make claims against what is an account there that really we have collected from customers and should flow to customers.

TransAlta submits that it would not be in the best interests of customers for TransAlta to actively seek opportunities to make payments out of the RAR reserve, and that the Board should place no weight on the argument that TransAlta has failed to do so.

---

[627] Tr. p.2377-2379

TransAlta submits that the forecast revenue adjustment expenses appropriately reflected the maximum liability at the time of the filing. TransAlta also notes that since the balance in the RAR reserve account is treated as no cost capital and as any balance as of 31 December 2000 is proposed to be transferred to the Balancing Pool, customers should be indifferent to the balance in the RAR reserve.

Accordingly, TransAlta submits that the Board should approve the revenue adjustment expenses as filed.

Board Findings

The Board agrees with the Intervenors that it is highly unlikely that the maximum liability would ever be required as a revenue adjustment expense. The Board notes the past history of claims under the RAR. The Board considers that the RAR reserve should be reduced to a more realistic level.

Accordingly, the Board agrees with the specific recommendations of the FIRM Customers set out above and the Board directs TransAlta, in its refiling, to follow those recommendations and reduce its revenue requirement by $8.808 million in 1999 and $9.031 million in 2000.

The Board directs TransAlta to apply to the Board for approval to transfer the balance remaining in the reserve for revenue adjustment claims at the end of the year 2000 to the Balancing Pool on 1 January 2001. The Board approves that any subsequent payments required under the RAR would be from the Balancing Pool during the PPA period.

(2) Excess Energy Cost

The Board reviewed the method by which TransAlta is compensated for payments made for excess energy:

> I would like to revisit this issue (small power excess energy) to be sure that the currently-approved method is robust enough to deal with any changed circumstances since 1996, including the fact that we have a system which is now more tight than it was in 1996.[628]

The review then dealt with whether the loss that TransAlta had with respect to paying the legislated price for excess energy could be offset at times by the pool price being above the legislated price. The following discussion ensued:

[628] Tr. p.3757

Q Just going up to a higher level here, is it correct, then, that the current approved method for excess energy has TransAlta bearing the loss for all hours where the contract price exceeds the pool price, but you would receive a benefit when the pool price is above the contract price?

A MR. WAY: I would say that's true, sir, if the pool price ever went above the contract price, and I think we can count those hours on very few fingers here.

Q Yes. Well, actually, I guess it is exhibit -- the one that you did provide -- Exhibit 107. I think it looks like there is some 322 hours when the pool price is expected to be above $60 a megawatt hour. So it would be in those small number of hours that there would be an offset?

A MR. WAY: There would be an offset in those hours.

Q As the system becomes more constrained, and as the pool price rises, then the cost of the small power excess energy borne by TransAlta would decrease?

A MR. WAY: Yes, sir, and the inverse as the system --

Q And the reverse, yes. If this excess energy were dispatchable, in fact, if any of the small power were dispatchable, it would, in fact, be setting the pool price in a number of hours?

A MR. WAY: That is a bit of a hypothetical, but if it was dispatchable by TransAlta, yes, we would not be dispatching it very frequently. If it was dispatchable by the owner, and these contracts didn't exist, then they would be looking at a price, I guess, acceptable to them, I believe. If you were thinking of it being dispatchable by us, yes, we would probably bid it in at 6 cents, and it wouldn't run very frequently.

The Board also questioned TransAlta on the specific method used to price the excess energy.

Position of TransAlta

It remains TransAlta's position that its contractual obligation to purchase excess energy at the legislated price was assumed prudently and in the interest of supporting the diversification initiative envisaged by the SPRD Act. TransAlta submitted that now that the supply/demand situation has become acute, and energy from all sources is more often required to meet provincial demand, the Board should consider the payments for excess energy to be prudent as they are clearly needed by the system as a whole. Accordingly, TransAlta submitted that it should be paid for all costs associated with small power excess energy during the test year period.

Board Findings

The Board notes that the average contract price for the excess energy is approximately $60/MWh for 1999 and 2000 whereas TransAlta's forecast of average pool price for the excess energy is approximately $38/MWh for 1999 and $31/MWh for 2000. The Board also notes that the differential between contract price and pool price has significantly narrowed since 1996 when the original forecast pool price was approximately $14/MWh. The Board recognizes that the excess energy is more valuable as the supply/demand situation becomes more acute. However, the Board considers that pool price provides the proper measure of the value of the excess energy rather than contract price.

Accordingly, the Board is not persuaded that circumstances have changed sufficiently to warrant a change to the previous Board findings respecting excess energy costs. The Board, in Decision U97065 stated the following:

> In this regard, the Board notes that no changes to the SPRD Act have been made that relieve TransAlta of the risk of acquiring energy in excess of the capacity allocation. Further, the Board considers that both the competitive nature of the restructured industry and TransAlta's reluctance to incur any of the SPRD Act costs calls into question TransAlta's willingness to pursue an uneconomic alternative where the SPRD unit cost exceeds the pool price. In consideration of the foregoing, the Board rejects TransAlta's claim that it has prudently acquired the excess energy.[629]

Therefore, the Board directs TransAlta, in its refiling to continue to calculate the claim for excess energy costs at the hourly pool price rather than at the contract price.

The Board considers that the claim for excess energy cost should be calculated using the forecast excess energy in each hour multiplied by the pool price for that hour. The Board notes that TransAlta used the following method to estimate the claim for excess energy costs:

> For the ENPRO modeling, an hourly average capacity was calculated for all Small Power Producers by dividing the forecast monthly energy amounts by the number of hours in each month. The calculated hourly average capacity for each month is shown in Section 2.2.4.7 Table 12 of the filing, and includes a small amount of capacity that is associated with excess energy. The capacity is modeled by ENPRO as a "must run" generator with no forced outages or derates, which results in a single level of output for all hours in the month. The revenue that TransAlta is forecasting to receive from the Pool for the energy is calculated on an hourly basis, however since the energy forecast in each hour of the month is constant, the resulting revenue is the same as the monthly energy volume

[629] Decision U97065, p.562-563

> multiplied by the average monthly pool price…TransAlta's forecast of payments for the excess energy was done by multiplying the forecast excess energy in each month by the average pool price in that month, which as stated above, is the same as performing the calculation using a constant volume for each hour of the month and the hourly pool prices for that month.[630]

The Board accepts, for the purposes of this Decision, that it is appropriate to consider that the supply of excess energy is constant for each hour of the month. Given that assumption, the Board is satisfied that TransAlta's method achieves the same result as multiplying the excess energy in each hour by the pool price in that hour. Accordingly, the Board directs TransAlta, in its refiling, to continue to use the above method to calculate the claim for excess energy costs.

[630] Exhibit 153

3. TRANSCO

(a) Necessary Working Capital

A Lead/Lag Study is used to determine the average necessary working capital (NWC) required to pay operating expenses (including all taxes) in advance of collecting revenues. Generally, the payment of expenses occurs in advance of the receipt of revenues, and therefore leads revenue collection.

The supply of electric service is followed by the payment of expenses, which is then followed by the collection of the associated revenues. Expenses lag the provision of service while revenue lags both the provision of service and the payment of expenses. Some expenses occur in advance of providing the service, but generally the payment of expenses occurs after service has been provided. A revenue or expense lag is measured as the interval in days from the provision of service to the collection of the revenue or the payment of the expense. There are two separate studies involved:

- the number of lag days in the collection of revenue, and
- the number of lag days in the payment of operating expenses, income taxes, and GST.

The net lag or net lead is the difference between the number of lag days in the collection of revenue and the number lag days in the payment of operating expense. A positive number is referred to as a net lag and means that the payment of expenses precedes the receipt of revenues thereby increasing the NWC requirement. A negative number is referred to as a net lead and means that the receipt of revenues precedes the payment of expenses thus reducing the NWC requirement.

TransAlta used 1997 recorded results in the lead/lag study, and where appropriate, adjustments to reflect subsequent changes to the timing of payments were incorporated.

The following table sets out the requested TRANSCO NWC for 1999 and 2000.

3. TRANSCO
(a) Necessary Working Capital

		$ millions			
Cost Category	**Lag/(Lead) (% of Yr.)**	**1999 Expense**	**1999 NWC**	**2000 Expense**	**2000 NWC**
Income Tax Installments	8.6	35.8	3.1	37.2	3.2
Purchase Power Costs	N/A				
Cash Operating Expense[631]	4.8	42.8	2.1	38.1	1.8
Depreciation (1/2)	13.1	27.3	3.6	28.5	3.7
Preferred equity	0.6	5.3	0.0	5.3	0.0
Common Equity (Ret earn)	13.1	12.9	1.7	12.9	1.7
Common Equity (Div)	0.6	12.9	0.1	12.9	0.1
Debt Interest	(8.7)	26.2	(2.3)	24.4	(2.1)
GST	(0.6)	13.3	(0.1)	13.1	(0.1)
Materials & Supplies (Mid)	N/A	4.8	4.8	4.4	4.4
Unamortized software	N/A	6.0	6.0	6.9	6.9
Total NWC			**18.9**		**19.7**

Source: Exhibit 59 TAU.T-4 Revised

The percentages shown in the second column above represent the net lag or net lead days expressed as a percentage of 365 days.

TransAlta noted that its Lead/Lag Study was provided in evidence[632] and no interested parties raised any objections. TransAlta submitted that the study should be accepted in full by the Board.

Board Findings

The Board has reviewed the Lead/Lag Study and has found the net lead and net lag days for each expense category to be reasonable. The Board notes that no objections were raised with respect to TransAlta's Lead/Lag Study. Accordingly, the Board approves the net lead/lag percentages shown in the above table for each TRANSCO expense category.

The Board notes that TransAlta has been directed to make a number of changes to the costs in each expense category. The Board directs TransAlta, in its refiling, to revise the 1999 and 2000 NWC using the Board approved costs in each expense category.

[631] Includes Taxes Other than Income
[632] Exhibit 13, Binder #1, Section 6.3

(b) Cash Operating Expense

TransAlta applied for the following cash operating expense items for TRANSCO for 1999 and 2000.

Cash Operating Expenses – TRANSCO (millions)	1999	2000
Total Operating Labour	12.0	12.2
General Operating Expenses	3.7	3.8
Other Power Pool and Transmission Administrator Receipts	-0.4	-5.9
Corporate Services Allocation	13.9	14.1
Totals	29.2	24.2

(1) Operating and Maintenance

(A) Labour–Duplication of Planning Costs

The Board has dealt with this issue under the Transmission, Planning and Provision of New Facilities, Part 1–General, Section 3(b)(2), of this Decision.

(B) Gross Labour Escalation

The Board has dealt with labour and escalation rates in the GENCO section of this Decision. For the same reasons as set out in that section, the Board approves TransAlta TRANSCO forecast labour and escalation rates. The Board notes that in the TransAlta Pension Reserve Section of this Decision the Board directed a reduction to pension expense which will in turn reduce the operating labour component of TRANSCO cash operating expenses.

(2) Taxes Other Than Income Tax

TransAlta forecast taxes other than income of $13.7 million for 1999 and $13.9 million for 2000 for the TRANSCO business unit.

Position of ENMAX

ENMAX proposed a global adjustment to the total GENCO, TRANSCO and DISCO property taxes. ENMAX submitted that the Board should reduce the total amount allowed for taxes other than income taxes by $2 million for each of 1999 and 2000 to reflect current trends. ENMAX suggested that the forecast should not include increases that will not materialize.

Position of TransAlta

TransAlta submitted that the ENMAX submission that taxes other that income be reduced by $2.0 million in each of 1999 and 2000 has not been supported by any credible evidence in this proceeding. Given the evidence on the record, TransAlta submitted that the ENMAX submission with respect to property tax was without merit and ought to be rejected.

Board Findings

The Board notes that TransAlta proposed a total Utility forecast for GENCO, TRANSCO and DISCO of $45.2 million in 1999 and $45.7 million in 2000 for taxes other than income. These figures included $1.0 million in 1999 and $1.1 million in 2000 for water rentals. The Board also notes that the $2.0 million reduction proposed by ENMAX for the combined business units translates into an approximate 4.5% reduction to TransAlta's forecast excluding water rentals.

The Board has reviewed TransAlta's reasons for the forecast increase in taxes other than income tax.[633] In view of these reasons, the Board considers that it would be reasonable to limit the forecast increase to no more than 5% for each business unit for 1999 over 1998 and no more than a further 1.5% increase for 2000 over 1999. Accordingly, the Board rejects the ENMAX proposal to reduce each of GENCO, TRANSCO and DISCO by 4.5%.

The Board notes that TransAlta is proposing a 4.6% increase to TRANSCO property tax for 1999 and a further 1.5% increase for 2000. For the reasons set out above, the Board accepts these increases as reasonable and appropriate. Accordingly, the Board approves a TRANSCO forecast of $13.7 million for 1999 and $13.9 million for 2000 for taxes other than income.

(c) Income Tax

TransAlta stated that income taxes are now calculated separately for TRANSCO. TransAlta's prior practice was to calculate income taxes on a corporate basis and allocate the result to generation, transmission and distribution. All actual cumulative timing differences including capital cost allowance are directly assigned to each function.[634]

For TRANSCO TransAlta included, in its Application, a forecast income tax of $35.8 million for 1999 and $37.2 million for 2000.[635]

Board Findings

For purposes of this Decision, the Board approves the method, set out in Part 4–General, Section 1(f), Income Tax, of this Decision, to calculate the component of revenue requirement attributable to income taxes for TRANSCO. The Board directs TransAlta, in its refiling, to provide detailed calculations for the recalculated income taxes to TRANSCO using the approved method described in the section noted above.

---

[633] ENMAX.TAU-40
[634] Application Section 6.2
[635] Exhibit 59

4. DISCO

(a) Rate Base

(1) Capital Additions

TransAlta forecast DISCO capital additions in the amount of $62.8 million in 1999 and $58.8 million in 2000.[636] The major capital projects are shown in the following table:

	($Millions)	
DISCO Capital Project	**1999**	**2000**
Oilfield Metering Installation Project	$2.5	$2.5
REA Purchases	2.9	2.9
Distribution Customers	38.8	36.4
Outage Management Systems	2.0	0.0
Interactive Voice Response (IVR) System	0.5	1.0
Efficient Operation Improvements	1.1	1.1
Distribution Urgent Repairs	3.4	3.4
Distribution Pole Management	1.9	1.9
Other Planned Maintenance	1.0	1.0
Distribution Planned Maintenance—Subtotal	2.9	2.9
Distribution Line Moves	2.0	2.0
System Capacity Increases and Improvements	6.1	5.8
Buildings, Meters and Tools	0.6	0.8
Total	**$62.8**	**$58.8**

TransAlta noted that average DISCO capital additions from 1992 to 1998 were $32.5 million for system projects and $55.1 million for DISCO customer projects for a total average of $87.6 million.[637] The 1998 current estimate is $33.0 million for system projects and $50.8 million for customer projects ($12.2 million of customer projects to CWIP) for total DISCO capital additions of $71.6 million.[638] The 1999 and 2000 forecasts are $24.0 million and $22.4 million for system projects and $38.8 million and $36.4 million for customer projects respectively.[639]

TransAlta further noted that the forecasts for 1999 and 2000 are much lower than historical amounts. One reason for this decline is the process change regarding underground subdivisions, which has now been turned over to developers to take accountability for providing their own

[636] TransAlta Evidence, Section 4.3
[637] Tr. p.3678
[638] Exhibit 64; Revised SPPA.TAU-10(d)
[639] Tr. p.3678

electrical services. This reduced the forecast by $10 million for each year.[640] The remaining reduction in forecast is due to TransAlta's continuing efforts to reduce costs for its customers. TransAlta submitted that its 1999 and 2000 forecasts were reasonable and should be approved by the Board.

(A) Generic Capital Additions Adjustment

Position of the FIRM Customers

The FIRM Customers submitted that a 20% overall reduction to TransAlta's forecast of DISCO capital additions would not be unreasonable having regard to TransAlta's history of over-forecasting. If for no other reason, this adjustment is appropriate, since TransAlta directly benefits from any reductions to Board approved forecasts. Ironically, senior management also benefit through Incentive Compensation payments.[641]

Based on statements made by TransAlta's panel, it appears the capital budget is based on a build up of potential projects starting at the department level and ending with final approval at the Executive Committee level. It is also apparent that, in many instances, projects contemplated within the approved capital budget never proceed or are deferred for a variety of reasons. There was nothing given in evidence to suggest that this process included a mechanism which took into account previous forecasting errors.

For the period identified by the Board in Decision U97065 (being 1992 to 1995 inclusive), TransAlta experienced chronic over forecasting for each of the four years in question ranging from 18.1% to 23.8%.[642] For 1996, the capital additions forecast was filed 1 November 1995 and, presumably, reflected TransAlta's best estimates. There was no improvement and, again, capital additions for 1996 were over-forecast by $50.4 million or 26.1%.[643]

No evidence has been provided by TransAlta to suggest its procedure for forecasting capital additions has been changed in any way to correct these problems and thereby provide some element of comfort the 1999/2000 capital additions forecast do not suffer from the same problem.

Capital additions for 1997 and 1998 were the subject of negotiated settlements and TransAlta did not provide any comparison of forecast to actual capital expenditures for these years.

---

[640] IPCAA.TAU-45; Tr. p.2528
[641] Tr. p.2401
[642] Exhibit 93
[643] Exhibit 93

Position of TransAlta

TransAlta acknowledged historical problems with over-forecasting capital additions and recognized the Board's reduction in Decision U97065. It is precisely for this reason that TransAlta filed a comprehensive analysis of capital projects in full compliance with Board Direction TAU-04. All major projects were explained in detail in the Application, Information Responses and through witness testimony.

TransAlta further submitted that it is not helpful to compare TransAlta's current Application with the results in its 1996 filing and ask the Board to make arbitrary adjustments accordingly. As there were Negotiated Settlements for both 1997 and 1998, there is no forecasting track record available for the last two years and TransAlta submitted it would be unfair to make a generic reduction to TransAlta's 1999 and 2000 forecasts based on data three years out-of-date.

TransAlta submitted, therefore, that the 1999/2000 DISCO capital addition forecast should be dealt with on its own merit. The 1999/2000 Application provided a significant amount of detail regarding individual capital projects and several of these projects were reviewed in detail throughout the proceeding. TransAlta submitted that sufficient information has been provided to substantiate its DISCO capital forecast, and it would be inappropriate for the Board to make a general disallowance of costs as suggested by the FIRM Customers.

Board Findings

The Board notes TransAlta position that it would be unfair to make a generic reduction to TransAlta's 1999 and 2000 forecasts based on data that is three years out-of-date. The Board also notes that TransAlta filed an analysis of individual major capital projects in compliance with Board Direction TAU-04.

The Board, for the purposes of this Decision, will not make a generic adjustment to TransAlta's proposed DISCO capital expenditures. Rather, the Board will examine each of the major projects and make any adjustments on an individual project basis as required. The Board notes that as a result of its review and adjustment to individual projects below, TransAlta's overall proposed DISCO capital expenditures have been reduced by approximately 9%.

(B) Oilfield Metering Installation Project

Position of the FIRM Customers

TransAlta proposed to expend $2,500 per service to install oilfield meters on facilities that are currently unmetered.[644] In the 1996 Phase II proceeding, TransAlta, after changing their position, eventually proposed to install meters on 3,000 oilfield services over some undetermined time

[644] AFE Time-of-Use Metering in Section 4.3 of the Application

frame.[645] In the current 1999/2000 GTA, TransAlta proposed to install these meters over three years, starting in 1999, at a total cost of $7.5 million.

There are a number of issues regarding this capital expenditure proposal. First, TransAlta has stated they will not proceed with the installation of meters until the Board has approved their 1996 Phase II proposal on this issue.[646] Given the considerable coordination effort required for TransAlta to interface with oilfield customers, who will be required to modify the electric service on their side of the meter, considerable lead time would be required to launch this program. In 1998 (when this forecast was developed) TransAlta could not have expected a 1996 Phase II decision until part way through 1999. The request for capital costs for the full 1,000 meters in 1999 was inappropriate.

Second, the need for these meters remains questionable. Industry presented its views strongly in the 1996 Phase II argument against this program. The inclusion of $7.5 million for meters over three years will increase the oilfield related rate base by some 12 to 14% (assuming all costs are allocated to oilfield customers, as TransAlta suggested).[647] After the program is completed, only 20% (3,000/14,000 total) of the unmetered accounts will have been converted.

Third, customers object to TransAlta bolstering its 1996 Phase II argument while under cross-examination. At no time during the 1996 Phase II proceeding did TransAlta raise the argument that some oilfield customers were in favour of the installation of meters since they were "on the wrong side of the averaging line."[648] The vast majority of oilfield customers are opposed to the potential rate increases they will experience from TransAlta's proposed meter installation program for no real benefit in the majority of cases.

Fourth, the level of investment per meter, $2,500, is overstated. During the 1996 Phase II process, evidence was submitted by IPPSA/SPPA showing the cost to an oilfield customer to upgrade the secondary equipment to accommodate a demand meter was, on average, $1,572. The per service cost quoted by TransAlta in this proceeding was the maximum investment level proposed. It is inappropriate for TransAlta to request approval for capital expenditures to the maximum amount when the only evidence available suggest the average investment will be less.

Finally, the type of metering proposed by TransAlta should be clarified. The time-of-use meters proposed are not hourly interval meters that would allow for oilfield customers to utilize an hourly pool price flow through type of rate. The meters proposed are only capable of recording / totaling energy use in some pre-defined time intervals. (on-peak, off-peak, shoulder times, etc.) Board approval allowing TransAlta to install and own these meters prior to retail competition

[645] Please see IPPSA/SPPA 1996 TransAlta Phase II Argument (Section 7) and Reply Argument (Section 5) for discussion and further references on this issue.

[646] Tr. p.2661, p.2662

[647] Tr. p.2663

[648] Tr. p.2664-2665

will give TransAlta the ability to pre-determine future rate structures for oilfield customers and will also provide TransAlta with a competitive advantage over other potential providers. As noted in the 1996 Phase II argument, TransAlta should not be allowed to take away the "choice" portion of "customer choice" (especially prior to 2001).

Based on the foregoing, the FIRM Customers submitted that this was another example of TransAlta's over-forecasting of capital additions. If the Board allows TransAlta to install meters on existing unmetered services and/or allows TransAlta to invest in electric equipment on the customer's side of the meter, then the appropriate costs should be brought forward for review in TransAlta's next DISCO Phase I proceeding.

Position of TransAlta

The FIRM Customers asserted that the timing of the 1996 Phase II decision precluded the implementation of the metering program as forecast in the Application. TransAlta noted that it filed its 1996 Phase II Application seeking new rates to take effect 1 April 1999. This time frame would have provided ample opportunity to begin implementation of the meter installation program. As the forecast prepared by TransAlta is a comprehensive, forward looking program, it would be inappropriate to pick and choose which items proceed based on developments since the Application was prepared and filed.

The FIRM Customers questioned the level of investment per meter, referring to evidence provided by TransAlta and by IPPSA/SPPA in TransAlta's 1996 Phase II rate application. TransAlta's 1999/2000 Phase I Application was based on the most current cost information available at the time of filing. These current cost estimates were not challenged in the hearing and TransAlta submits that these costs are reasonable and should be approved by the Board.

The FIRM Customers argued that the Time-of-Use Metering program impedes future customer choice, both due to the types of meters being installed and since the metering is being installed prior to the advent of customer choice. The FIRM Customers' argument is contradictory - on one hand the cost is argued to be prohibitive for the meters proposed by TransAlta, and on the other, the FIRM Customers argue in favour of a far more expensive metering standard than that proposed by TransAlta. TransAlta submitted that the metering program is a reasonable compromise between no metering and metering which is far more elaborate than could be rationalized by the size of the services themselves.

Secondly, the provision of metering services is presently regulated, and is expected to remain regulated until at least 2005. To argue that efficient and effective programs should not be implemented now due to possible changes in industry structure several years hence is unreasonable.

Thirdly, there is no evidence to substantiate the FIRM Customers' claim that installation of these meters will give TransAlta any competitive advantage over other potential providers by pre-determining future rate structures. The metering information available as a result of this program

will enable all retailers to develop more creative offers for these services than is presently possible with unmetered services.

TransAlta therefore submitted that the FIRM Customers' argument is not substantiated, and that the Board should approve the Oilfield Meter Upgrades as filed.

Board Findings

The Board notes that TransAlta stated that the need for oilfield metering was being driven by the 1996 Phase II rate design and that TransAlta did not propose to initiate the project until after the Board had approved the rate proposal on this issue. The Board, in Decision U99035, found that

> customers should be given the choice as to whether or not to install or upgrade meters, rather than being forced to install/upgrade meters now.
>
> and
>
> The Board considers that, as customers have the choice of installing and/or upgrading meters at their convenience, the cost of supplying and installing the meters should be borne by the customers requesting the service.[649]

The Board notes that each oilfield customer will have the opportunity to choose metering (e.g. no meter, a standard non-time-of-use meter, an interval meter, a time-of-use meter capable of measuring energy use on an hourly basis) consistent with the retail services being offered. The Board further notes that any extra costs of metering will be borne by the customer requesting the service. For these reasons, the Board finds it unnecessary to approve any DISCO capital costs for additional oilfield meter installations for TransAlta.

Therefore, as a result of the above noted findings, the Board directs TransAlta, in its refiling, to remove the $2.5 million dollars for each of the years 1999 and 2000 forecast for oilfield metering installations.

(C) Purchases of REAs

Position of the FIRM Customers

TransAlta included a forecast DISCO capital cost of $5.8 million (approximately $2.9 million for each of 1999 and 2000) for the purchase of REA systems.

The FIRM Customers strongly objected to the inclusion of the $5.8 million, or any amount, forecast for the purchase of REAs. The same objection also applied with regard to any operating costs associated with such acquisitions. The FIRM Customers submitted that all such sums

[649] p.96

should be removed from TransAlta's filing since the request is neither justified by history or by recent trends.

From an historical perspective, the evidence indicated for the five years, 1994 to 1998, TransAlta spent an average of $1.12M per year to acquire REAs.[650] Further, TransAlta stated there were seven outstanding offers to purchase REAs at the time of filing at a cost of $1.6 million.[651] At an average price of $230,000 per REA, it appears TransAlta anticipated purchasing more than 25 REAs over the next two years. This number is nowhere near the average of 1.2 REAs purchased during the period 1994 through, to and including, 1998.

To shore up its position, TransAlta rationalized its position on the basis of "recent trends."[652] However, like historical trends, recent trends fail to support TransAlta's request. In particular, when both sides of the equation are taken into account, recent events show the repurchase by REA's of their former assets should be taken into account as an offset to REA purchases by TransAlta.

Not surprisingly, TransAlta admitted it does not treat REA inquiries to repurchase lines from TransAlta with the same degree of enthusiasm as the reverse. TransAlta also tried to argue there is "an order of magnitude difference" between the two "sides."[653] While this may be true in the limited context of individual REAs purchasing pieces of line, it fails to take into account the inquiries for repurchase of more substantial portions of TransAlta's distribution system. Clearly, there is little value or support for any forecast based solely on the influences favouring the desired outcome. In this instance, TransAlta does not give adequate consideration to important factors adverse to its position.

For example, TransAlta admitted to being aware of recent REA approaches to repurchase distribution systems, including discussions at the Contract Policy Committee level. The FIRM Customers noted that the REAs and the Utilities discuss contractual matters, policies and procedures through the Contract Policy Committee. TransAlta is also aware of the Entwistle Magnolia proposal to purchase a large amount of distribution line back from TransAlta.[654] TransAlta's witness, Mr. Millar, also noted other approaches by REAs to repurchase "individual pieces of line that they had formerly owned."[655] Notwithstanding this apparent awareness, TransAlta chose to disregard these trends in its evidence.

Another factor to be considered is the fact this type of capital spending was not included in TransAlta's 1996 GTA filing even though there were REA purchases completed during 1994 and

[650] Exhibit 92;Tr. p.2535
[651] Tr. p.2533 corrected at Tr. p.2750
[652] Tr. p.2532
[653] Tr. p.2748
[654] Tr. p.2747, p.2748
[655] Tr. p.2746

1995. The FIRM Customers also noted AE did not seek any funding in its revenue requirement for this purpose.

Based on the foregoing and coupled with the fact TransAlta is unable to identify even one completed sale during the period between preparation of this filing and the hearing, the FIRM Customers submitted the $5.9 million capital additions forecast for purchase of REAs is inappropriate.

Position of the REAs

The REAs stated that it had reviewed the FIRM Customers' argument with respect to REA purchases and adopted the same. The REAs submitted some additional argument as follows.

Since the onset of deregulation in the electrical industry, TransAlta's actions in dealing with REAs at best, make it difficult for REAs to operate and manage their own systems and at worse, seem to be calculated to eliminate REAs from TransAlta's Service Area. The REAs referred to a letter that was sent to certain REAs considering amalgamation which outlined options available to REAs.[656] In cross-examination, Mr. Millar expressed concern that the REAs objected to the letter and attempted to characterize the letter as:

> Simply providing (REA) members a discussion of their various alternatives. So I am not clear on why someone would be objecting on their membership being informed of their alternatives.[657]

The REAs submitted that the letter was an attempt to interfere in REA affairs.

In support of the foregoing characterization of TransAlta's actions in dealing with REAs, the REAs noted the following:

- Line twinning problems;
- The attempt to impose a $75,000.00 per incident call out fee for emergency services during emergency conditions which affect both TransAlta and REA distribution facilities as discussed in REA/AAMDC.TAU-17 (i) and Tr. p.2724;
- The increase in material loading charges from 6% to 13% for those REAs that manage their own operations and maintenance discussed at REA/AAMDC.TAU-21 and Tr. p.2731 (although to be fair, it became apparent during this discussion that TransAlta would prefer not to supply materials to Contract "C" REAs at all); and
- The interference in REA internal affairs discussed in REA/AAMDC.TAU-13 and Tr. p.2754. While on this point, TransAlta tried to leave the impression that they will only

[656] REA/AAMDC.TAU-13
[657] Tr. p.2755

approach REA's to sell out if they receive a formal written offer.[658] The letter appended to REA/AAMDC.TAU-13 disclosed otherwise.

Other indicia include the matter discussed in REA/AAMDC.TAU-23 where TransAlta equated moving a building through one utility's service area into another utility's service area with a situation where service areas overlap. It does not make practical sense to have two sets of lineman in attendance to move buildings along a road that is crossed by both REA and TransAlta distribution lines in their concurrent service areas.

The statement in REA/AAMDC.TAU-24 that the TransAlta representatives who negotiated the 1997 Master Contract with REAs were replaced by new people to negotiate the changes to the policies and procedures that accompany the Master Contract was not denied by TransAlta. While there may well have been no costs attributable to the negotiations of the 1997 Master Contract due to these personnel changes, it surely made the negotiation process more difficult for the REAs.

The REAs submitted that a pattern of not "playing fair" emerged.

As contrast, the situation is quite a bit different when TransAlta Utilities Corporation is dealing with TransAlta Energy Corporation. There appears to be a close working relationship between the two companies. This is not surprising and this is not wrong, however for obvious reasons it is something that should be transparent.

Mr. Hosie indicated that the cost of hiring contractors to "backfill," offsets the revenues from TransAlta Energy and "over the year it is a very close match." Further, TransAlta stated that there is no profit from this activity.[659]

On a topic such as the provision of services to a non-regulated sister company, the utility should be directed to record the costs and revenues in great detail and prove that the transactions are properly accounted for. This is not being done and the REAs submitted that TransAlta should be directed to do so.

Compare this approach with that respecting material handling where 6% is the cost. TransAlta charges Contract "C" REAs 13%. It is apparent that:

- There is a profit; and
- TransAlta's present attitude towards the REAs can be discerned by the contrast with the way it deals with TransAlta Energy.

[658] Tr. p.2745
[659] Tr. p.2743

In summary, the Board has been provided with several instances where TransAlta's actions appear to be tailored to discourage REAs. The REAs believes that distribution facilities will continue to be a regulated part of Alberta's electrical system. The REAs have and will continue to be useful in keeping electrical costs to rural residents reasonable and in fact, an REA presence provides the only real evidence of competitive forces in distribution. The REAs suggested that it would be detrimental to the Province if a Board decision aided TransAlta in buying out REAs.

In result, the REAs believed that TransAlta should not be encouraged to buy out REAs (with the resulting illogical elimination of competition that results). The REAs submitted that the Board should deny TransAlta's request for the forecast DISCO capital additions of $2.9 million dollars for each of the years 1999 and 2000 for REA purchases.

Position of TransAlta

The FIRM Customers and the REAs both recommend removing from TransAlta's DISCO capital additions the amounts forecast to be spent purchasing REAs in both 1999 and 2000.

First, TransAlta notes that the Board has approved similar expenditures in previous filings, and therefore forecasting such costs is consistent with historical treatment.

Second, TransAlta has documented the number of offers outstanding at the time of filing which signify a significant increase in the purchase of REAs. Further, Mr. Millar elaborated on the various factors influencing REAs that have been raised in conversations between Mr. Millar and REA members.[660] It would have been unreasonable for TransAlta to ignore these clear indications in developing its forecast.

As TransAlta stated during the course of the hearing, TransAlta seeks Board approval of its Application which was prepared on a forecast basis. Given the offers then outstanding, TransAlta submitted that its forecast was reasonable at the time of filing and ought to be approved by the Board.

The REAs also argued that TransAlta is inconsistent in its forecasts by omitting the repurchase by various REAs of small portions of 25 kV line previously owned by the REAs. As Mr. Millar indicated, relative to the purchase of an entire REA, these portions of line would have an insignificant impact:

> my understanding of these issues around repurchasing lines led me to believe that we were talking a fairly small amount of line. So there's definitely an order of magnitude difference.[661]

[660] Tr. p.3344, p.3345
[661] Tr. p.2748

Board Findings

The Board notes the comments of the REAs and, as directed in Part 1-General, the Board has directed TransAlta to report on regulated and non-regulated transactions.

The Board notes the REAs concern that TransAlta deals differently with REAs than it does with TransAlta Energy Corporation. The Board considers that both parties should be treated similarly for services including material loading charges and incident call-out fees for emergency services. However, there may be or could be some charges in the REA schedule of charges that are rarely used. There may be an incentive to have outdated or inappropriate charges apply to unregulated affiliates. Accordingly, the Board directs TransAlta to apply the same schedule of charges to its non-regulated affiliates effective 1 January 1999 as it charges the REAs or the market value whichever is higher.

The Board accepts the position of the Intervenors and considers that forecasts for purchases of REAs should be removed from forecast capital additions. However, the Board considers that forecast additional revenues should also be removed.[662] The Board notes that, if TransAlta purchases any REAs, TransAlta will receive the incremental revenues flowing from the purchase to offset the incremental costs associated with the purchase. The Board considers that its Decision to remove forecast revenues and costs will provide the proper incentives for purchase/sale negotiations.

Accordingly, the Board directs TransAlta, in its refiling, to remove the forecast DISCO capital additions of $2.9 million dollars for each of the years 1999 and 2000 for purchases of REAs and to remove the increase in revenues in the amount of $0.2 million in 1999 and $0.4 million in 2000.

(D) Distribution Customers

TransAlta noted that these projects are required to connect new distribution customers as per TransAlta's standard investment policy. The majority of these jobs are under $25,000. In 1999, TransAlta stated that it intended to move underground subdivision design and construction to an open market. The 1999 and 2000 capital forecast reflected this proposed change in practice as follows:

Capital Forecast	1999	2000
New Customers	8,123	8,363
Avg. Cost Per Customer Connect	$4,600	$4,350
Total Cost	$37,400,000	$36,400,000

[662] Exhibit 92; Tr. p.2537

Board Findings

The Board notes that the Distribution Customers project is by far the most significant DISCO capital project. The Board has reviewed TransAlta's forecast growth in customers and the forecast cost per customer by customer class used to arrive at the 1999 and 2000 forecasts of $37.4 million and $36.4 million respectively.[663] The Board notes that 1999 capital expenditures were increased by $1.4 million from CWIP to arrive at total 1999 capital additions of $38.4 million. The Board is satisfied that the Distribution Customer capital costs are reasonable. The Board further notes that TransAlta has also included forecast revenues associated with this growth. The Board considers that the annual costs associated with any error in forecast capital costs is offset by a similar magnitude of error in forecast revenues.

Accordingly, the Board approves TransAlta's forecast capital costs for the Distribution Customers project.

(E) Remaining DISCO Capital Projects

Outage Management Systems

TransAlta noted that currently, customer trouble calls are received at TransAlta's new Call Centre 24 hours a day. Linemen are then dispatched through the automated dispatch system with the help of an in-truck computer. Linemen then patrol the line to find and repair the faulted equipment. The opportunity exists to automate the process of locating faults in the Call Centre so that the linemen can travel more directly to the problem area and restore service. An additional opportunity is to automate the collection of outage data. This data can then be used to identify chronic trouble areas so that maintenance or system improvements can be initiated.

TransAlta stated that this project will provide an outage management system in the Call Centre and in the linemen's trucks. The objective of the project is to reduce the time to locate, make repairs and restore service to the customer. Along with the automated capture of outage data, a more efficient and productive work environment will be created.

Interactive Voice Response System

TransAlta noted that currently, customers must speak to Call Centre personnel to report power outages or other service problems. As well, service restoration projections, account information or any other forms of information desired by customers can only be obtained by one on one conversations. The opportunity exists to automate the customer interaction process. The benefits include the ability to communicate with more customers during system problems. The system will also improve the Call Centre response time without the need for increased staff levels.

[663] FIRM.TAU-41(b)

TransAlta stated that the project is to install and implement an interactive voice response system in the Call Centre to provide more effective and efficient customer service.

Efficient Operation Improvements

TransAlta noted that through the use of improved software tools and available data from Point of Delivery metering installed in 1996, an opportunity exists to optimize 25 kV feeders, maximize equipment utilization and minimize distribution losses.

TransAlta stated that these projects consist of additions/relocations of normally open switches, capacitor banks, regulators, conductor upgrades, and phase balancing which will increase efficiency on the distribution system and minimize losses to decrease overall greenhouse gas emissions.

Distribution Urgent Repairs

TransAlta noted that component failures on the distribution system due to inclement weather, defective equipment, animal intrusions, vandalism, abnormal operating conditions, etc. causing outages to customers must be addressed in an expedient manner and ensure employee and public safety is not at risk.

TransAlta stated that the scope of this project is to repair damage to equipment that must be done on an emergency basis to provide a safe and reliable distribution system.

Distribution Planned Maintenance

TransAlta noted that aging distribution poles require a proactive program to manage the risk of employee and public safety, and ensure acceptable level of service. Extending the life of poles limits the number of new poles required and costs associated with replacement.

TransAlta stated that the pole management project involves the implementation of a plan to treat, stub, wrap and replace distribution poles to ensure public and personnel safety and maintain a reliable distribution system. The objective is a managed program to obtain maximum life of existing poles.

TransAlta stated the other maintenance projects provide a safe environment for employees and the public while maintaining an acceptable level of service.

Distribution Line Moves

TransAlta noted that several hundred requests are received each year from Alberta Transportation and Municipalities and customers to relocate distribution lines located on road allowance, highway right-of-ways, or private property to accommodate road widening or other concerns. Lines located on public road allowances must be moved at TransAlta's cost. Lines

located on easements on privately held land are moved at the cost of the person making the move request.

TransAlta stated that this project involved relocation of existing distribution lines in various locations.

System Capacity Increases and Improvements

TransAlta noted that as customer load grows, existing distribution lines require modifications to provide sufficient capacity and voltage.

TransAlta stated that these projects involve the installation of new lines, capacitor banks, regulators or reconductoring distribution lines in various locations to accommodate load growth. These projects provide adequate capacity and voltage support on distribution lines to accommodate load growth. Also, these projects involve the installation of new distribution lines to act as tie lines between load growth areas or as new feeders.

Buildings, Meters and Tools

These projects include:

- Additions and repairs to buildings outside of Calgary
- Refitting and repairs to existing meters
- Tools and instruments
- Centralized distribution operation tools

Board Findings

The Board has reviewed the above evidence respecting the remaining DISCO capital projects and recognizes that these projects are primarily customer service oriented. The Board notes that customers will benefit from the contemplated improvements in customer service. The Board is satisfied that the projects are needed and that the forecast costs are reasonable.

(2) Line Twinning

Position of the REAs

REA/AAMDC.TAU-16 dealt with instances of line twinning in TransAlta's service area. These events are cause for concern to the REAs and the REA affected (SouthAlta REA Ltd.) as REA owned facilities are left redundant. In summary, a TransAlta customer required three-phase service in an area served by an REA single-phase distribution line. TransAlta's preference was to construct a three-phase distribution line and salvage the REA single-phase line leaving TransAlta with more assets and the REA with less. The REA's preference was to upgrade the single-phase line to a three-phase and allow TransAlta to serve the customer off of it. In each case, the REAs

stated that TransAlta constructed a new three-phase distribution line which has the following unpleasant results.

- The REA loses assets and becomes a little less worthy or relevant.
- Customers pay for duplicate facilities at costs that were not prudently incurred and did not aid in the economic, orderly and efficient development and operation of Alberta's electric system.

TransAlta's witnesses attempted to show there is no need for concern because the new requirement was for a three-phase line. With respect, this appears to be misdirection. The REA is fully capable of upgrading single-phase lines to three-phase and operating them.

In reviewing TransAlta's high level principles,[664] the first being to provide the service to the customer that is required, there is nothing to indicate that the REA could not have provided the facilities up to the tap.

The second high level principle is based on cost and common sense indicates that the least possible cost would result from an upgrade, not a brand new line. Finally, the "operational complexities" principle indicates that replacing a piece of REA line with a piece of TransAlta line speaks for itself. Three small pieces of distribution line have now switched from REA to TransAlta in the overall system.

Mr. Millar made some comments that support REA ownership of these lines:

> In a number of cases, there are cases where ownership of line changes continuously. There is a portion of TransAlta line, a portion of REA line, and a portion of TransAlta line. Especially when we are talking fairly small lengths, our preference is not to have changes of ownership, especially if it is the first change in ownership on a particular circuit if we are going to be going back and forth, and especially if the section of line that would be owned by the REA would be quite small compared to the total line length.[665]

REA/AAMDC.TAU-16(f) states that at all these locations, the REA can salvage their redundant facilities and connect their individual services to the new TransAlta line with no applicable connection charge. It is reasonable to believe that the REA is reluctant to do this. Mr. Millar agreed that South Alta REA is one of the REAs that does not want to sell its facilities to TransAlta.[666] The FIRM Customers suggested it is improper to allow the same result through indirect means.

---

[664] Tr. p.2717
[665] Tr. p.2716
[666] Tr. p.2743

The REAs objected to TransAlta's characterization of an REA building a duplicate single-phase tap to a customer (for reasons that were not explained, but may well be justified) as "line twinning" in comparison to over 1.6 kilometers of three-phase distribution line.[667] The situations are not at all similar and, more importantly, the REA is not trying to put the costs into rate base whereas TransAlta is applying to include the costs in rate base.

As a final note, it does not matter if the situations that concern the REAs are called "line twinning" or "line paralleling." The result is the same. Duplicate facilities are built and it makes no sense to have the public pay for something the REA is willing to provide. It costs less to upgrade and TransAlta should not be allowed to undermine the relevance, utility and ability of REAs to provide service.

The examples provided by TransAlta are small but the principle is large and the REAs requests that the Board direct TransAlta to:

- remove the cost of constructing 1.6 km of three- phase distribution line from rate base.
- enter into negotiations with SouthAlta REA Ltd. for the sale of the duplicate facilities to SouthAlta REA Ltd. and in the event that agreement cannot be reached, that the matter be resolved pursuant to Part 6 of EU Act, the costs for which to be borne by TransAlta's shareholders.

Position of TransAlta

The REAs submitted that TransAlta built unnecessary 25 kV three-phase facilities and that these facilities (approximately 1.6 km) should be excluded from TransAlta's rate base. TransAlta submitted that this argument was flawed and an attempt to introduce new and erroneous evidence under the guise of argument.

First, as Mr. Millar stated under cross-examination, the three-phase 25 kV circuits constructed by TransAlta were required and continue to be required to provide service to customers requiring three-phase service.[668] This service could not be provided via the single-phase circuits owned by the REAs. Mr. Millar also stated that TransAlta had approached the REA in question about upgrading its existing single-phase circuit to a three-phase circuit in this particular instance. A timely solution regarding this issue could not be reached and therefore, TransAlta constructed the three-phase service in order to provide its customer with the service when required.[669] Any suggestion that the facilities should be excluded from rate base is unreasonable.

Second, the REAs imply that costs would have been lower had the REA upgraded its circuit, rather than TransAlta constructing a new circuit. As the REA is fully aware, standard industry

[667] Tr. p.2718
[668] Tr. p.2714
[669] Tr. p.2717

practice requires that when upgrading the circuits to three-phase configuration, it is necessary to shift the existing circuit out of the way, build a new three-phase circuit, and then salvage the original single-phase circuit. TransAlta submitted that no cost savings would have occurred, and arguably costs may have been higher had the REA carried out the work instead of TransAlta.

TransAlta suggested that the position put forth by the REAs is not relevant to these proceedings. It is an attempt to burden the Board with a contractual issue between the REAs involved and TransAlta, and an attempt to circumvent the arbitration provision of the contract should the continuing negotiations fail to reach success. Accordingly, TransAlta submitted that the Board should disregard the REA's argument and recommendations on these issues.

Board Findings

The Board notes that disputes between TransAlta and the REAs respecting the economic, orderly and efficient development and operation of distribution systems can be brought to the Board by way of an Application for resolution prior to construction. However, the Board encourages TransAlta and the REAs to negotiate successful resolutions to disputes of this nature.

The Board agrees with TransAlta that the matter of whether the REA or TransAlta could have constructed the 1.6 km of three-phase line in the most economic, orderly and efficient manner was not properly brought before the Board to be resolved in the context of the 1999/2000 proceeding. The Board notes that there is no dispute that a three-phase line was required to serve the new customer. The Board has no evidence to suggest that TransAlta's three-phase construction was not economic, orderly and efficient. Accordingly, the Board is not persuaded that the 1.6 km of three-phase line should be removed from TransAlta's rate base.

(3) Necessary Working Capital

A Lead/Lag Study is used to determine the average working capital required to pay operating expenses (including all taxes) in advance of collecting revenues, Generally, the payment of expenses occurs in advance of the receipt of revenues, and therefore leads revenue collection. The supply of electric service is followed by the payment of expenses, which is then followed by the collection of the associated revenues. Expenses lag the provision of service while revenue lags both the provision of service and the payment of expenses. Some expenses occur in advance of providing the service, but generally the payment of expenses occurs after service has been provided. A revenue or expense lag is measured as the interval in days from the provision of service to the collection of the revenue or the payment of the expense. There are two separate studies involved:

- the number of lag days in the collection of revenue, and
- the number of lag days in the payment of operating expenses, income taxes, and GST.

4. DISCO
(a) Rate Base

The net lag or net lead is the difference between the number of lag days in the collection of revenue and the number lag days in the payment of operating expense. A positive number is referred to as a net lag and means that the payment of expenses precedes the receipt of revenues thereby increasing the NWC requirement. A negative number is referred to as a net lead and means that the receipt of revenues precedes the payment of expenses thus reducing the NWC requirement.

TransAlta used 1997 recorded results in the lead/lag study, and where appropriate, adjustments to reflect subsequent changes to the timing of payments were incorporated.

The following table sets out the requested DISCO NWC for 1999 and 2000.

		$ millions			
Cost Category	**Lag/(Lead) (% of Yr.)**	**1999 Expense**	**1999 NWC**	**2000 Expense**	**2000 NWC**
Income tax installments	4.4	50.1	2.2	50.9	2.2
Purchase Power Costs	(3.1)	959.9	(29.8)	955.8	(29.6)
Cash Operating Expense[670]	(0.3)	103.1	(0.3)	105.7	(0.3)
Depreciation (1/2)	8.8	42.8	3.8	44.6	3.9
Preferred equity	(3.6)	3.5	(0.1)	3.4	(0.1)
Common Equity (Ret earn)	8.8	12.1	1.1	11.6	1.0
Common Equity (Div)	(3.6)	12.1	(0.4)	11.6	(0.4)
Debt Interest	(12.9)	16.8	(2.2)	15.0	(1.9)
GST	(3.2)	86.5	(2.8)	86.5	(2.8)
Materials & Supplies (Mid)	N/A	4.3	4.3	4.0	4.0
Unamortized software	N/A	15.1	15.1	25.5	25.5
Total NWC			**(9.1)**		**1.5**

Source: Exhibit 59 TAU.D-5 Revised

The percentages shown in the second column above represent the net lag or net lead days expressed as a percentage of 365 days.

TransAlta noted that its Lead/Lag Study was provided in evidence[671] and no interested parties raised any objections. TransAlta submitted that the study should be accepted in full by the Board.

Board Findings

The Board has reviewed the Lead/Lag Study and has found the net lead and net lag days for each expense category to be reasonable. The Board notes that no objections were raised with respect

[670] Includes Taxes Other than Income
[671] Exhibit 13, Binder #1, Section 6.3

to TransAlta's Lead/Lag Study. Accordingly, the Board approves the net lead/lag percentages shown in the table for each DISCO expense category.

The Board notes that TransAlta has been directed to make a number of changes to the costs in each expense category. The Board directs TransAlta, in its refiling, to revise the 1999 and 2000 NWC using the Board approved costs in each expense category.

(b) Cash Operating Expense

(1) General

TransAlta's DISCO cash operating expenses are shown by major component in the following table:

($ million)

Category	1996	1997	1998	**1999**	**2000**
Operating Labour	53.0	48.9	47.5	45.7	47.3
Corporate Services	29.4	30.9	34.7	34.0	34.4
General Operating	10.1	13.5	12.0	13.7	14.4
Taxes Other than Income	8.9	8.9	8.5	9.1	9.2
Total Cash Operating	101.4	102.2	102.7	102.5	**105.3**

Source: TransAlta Evidence, Schedule 4.2.1;Sch 4.2.2; ENMAX.TAU-40

General Operating expenses are further broken down in the following table:

($ million)

Category	1996	1997	1998	**1999**	**2000**
Materials	3.2	1.5	1.0	0.9	1.0
Staff Expenses	2.9	2.6	2.5	3.0	2.9
Vehicle Expenses	2.5	1.9	0.0	0.0	0.0
Office Expense	2.4	4.5	6.9	5.7	6.3
Other Expenses	1.7	1.3	1.3	2.1	2.1
Bad Debt Expense	2.0	1.6	0.9	1.4	1.4
NFR Expense	0.2	0.1	0.0	0.0	0.0
Insurance	N/A	N/A	N/A	0.4	0.4
Transfer to/from Capital	(4.7)	(0.2)	(0.6)	0.2	0.3
Total General Operating	10.1	13.3	12.0	**13.7**	**14.4**

Source: TransAlta Evidence Schedule 4.2.6

TransAlta noted that the downward trend of expenses in operating labour between 1996 and 1999 outlined in Section 4.2 is evidence of DISCO's successful focus on cost reduction. This has been accomplished with improved customer service through centralized customer handling and service dispatch and by implementing a Reliability Centered Maintenance (RCM) program. These changes have enabled DISCO to reduce its total operating labour by $7.3 million (14%).

Also of note is the establishment of TransAlta's Call Centre which became operational in 1998 and is at the core of many of DISCO's strategies for gaining operational efficiencies while providing a consistent and high standard of customer service. This facility, which is explained in CCA.TAU-40, provides customers with 24 hour access to TransAlta's services and has enabled TransAlta to improve the coordination of service activities through centralized dispatch. In addition to the efficiencies gained by centralizing customer handling and dispatch, TransAlta's RCM program has enabled it to reduce its DISCO brushing expense.

In summary, TransAlta submitted that the achievement of operating cost reductions in the DISCO function clearly demonstrated the reasonableness of the operating cost forecast for 1999 and 2000.

The Intervenors, however, recommended reductions to DISCO operating and maintenance costs for the following categories:

- labour and materials escalation rates
- marketing expenses
- bad debt expenses
- taxes other than income tax

The Board will deal with each of these categories in the following sub-sections.

(2) Labor and Materials Escalation

Position of the FIRM Customers

The FIRM Customers provided common argument and recommendations respecting GENCO, TRANSCO and DISCO Labour and Materials escalation. That argument is set out in the GENCO section of this Decision. The FIRM Customers stated that their argument and recommendations respecting TransAlta GENCO were equally applicable to TransAlta DISCO.

Position of TransAlta

TransAlta's position respecting Labour and Materials escalation is included in the GENCO section of this Decision.

Board Findings

The Board has dealt with labour and escalation rates in the GENCO section of this Decision. For the same reasons as set out in that section, the Board approves TransAlta DISCO's forecast labour and escalation rates. The Board notes that in the TransAlta Pension Reserve Section of this Decision the Board directed a reduction to pension expense which will in turn reduce the operating labour component of DISCO cash operating expenses.

(3) Advertising and Marketing

The cost of advertising and marketing programs is included in the office expense category of General operating expense.

Position of the FIRM Customers

In FIRM-TAU-37, TransAlta provided details on advertising programs in excess of $100,000, included as part of its office expenses.[672] As a matter of policy, the FIRM Customers believed that TransAlta should not be spending regulated Utility ratepayer money on several of the programs listed. The market is expected to change, with energy being supplied by retailers; not TransAlta (except to stable rate customers). In the lead up to this market change, TransAlta should not be using funds from ratepayers to pay for advertising benefiting either the Utility (providing stable rate power in competition with other marketers) or its marketing affiliate (through name recognition by using the TransAlta name in advertising) over other competitors. The FIRM Customers submitted that if TransAlta wants to position itself in the competitive market, it should do so with shareholder money. Specific programs that should be disallowed for ratemaking purposes are set forth in the following table.

Marketing Programs Recommended for Disallowance by FIRM Customers ($M)

	1999 Spending	2000 Spending
Weather Watch Sponsorship	$0.3	$0.3
Energy Marketing Programs	$0.5	$0.6
Customer Research	$0.1	$0.2
Website Development		$0.2
TOTAL	**$0.9**	**$1.3**

The FIRM Customers submitted that it is completely inappropriate for TransAlta to market energy to customers. This is a retail function starting in 2001. The Weather Watch sponsorship is image building advertising redounding to the competitive advantage of TransAlta and its affiliates in the new world. The Board should not just look at whether customers are being reached; but to what end. This type of advertising appears designed entirely for image building.

[672] Section 4.2.4.4

A regulated wires company does not need to market anything. Neither does a GENCO whose customers are its PPA buyers. Marketing is only needed for retail services.

Customer market research should also be disallowed, since such research largely benefits future unregulated activities. Website development for E-commerce is also largely a retail function, as the wires company's bills will be paid by retailers, not end-use customers (except possibly for stable rate option customers). In sum, given the imminent change in market structure, ratepayers should not fund marketing expenses primarily benefiting TransAlta's future retail activities. Therefore, $2.2 million of 1999-2000 marketing and advertising costs should be disallowed.

Position of TransAlta

TransAlta submitted that the FIRM Customers' argument that TransAlta is "using funds from ratepayers to pay for advertising benefiting either the Utility (providing stable rate power in competition with other marketers) or its marketing affiliate (through name recognition by using the TransAlta name in advertising) over other competitors" is not supported by the evidence.

As Mr. Tremblay stated translate has:

> ...an obligation to serve our existing customers in that time period [1999 and 2000], and in fact, as you pointed out, with an evolving structure in our industry, there is an increased amount of communication that is required with our customers to explain to them and to help communicate with them the various choices and options that will be available to them today and in the future, as the industry restructures.[673]

TransAlta submitted that it is appropriate for TransAlta to keep customers informed of the changes in the industry. This position was not challenged by any of the Intervenors in argument.

The FIRM Customers also argued that specific advertising line items that were shown in FIRM.TAU-37 should be disallowed by the Board. The first item the FIRM Customers challenged is the Weather Watch program. Mr. Tremblay explained the value of this program:

> We have undertaken some significant staff reductions and the closure of front counters in rural Alberta and some of our rural service area. Those initiatives, we have undertaken those to lower costs and improve service; however, some of the aspects at the front end of that transition some customers may have seen as a takeaway. So we had a concern about maintaining our visibility in rural Alberta, and there was some programs aimed at enabling TransAlta to undertake those transitions.[674]

---

[673] Tr. p.2635
[674] Tr. p.2955

Later, Mr. Tremblay testified that the Weather Watch program

> ...in fact reaches about 70 percent of our customers. It is actually an extremely efficient way for us to reach our customer base, which is primarily rural Alberta. So for us, that is a very effective way to reach our customers.[675]

TransAlta submitted that the Weather Watch program was helpful in facilitating the Call Centre reorganization which resulted in $4.5 million in annual savings to the customers.

The FIRM Customers also took a "shot gun" approach to the advertising programs entitled "Energy Marketing, Customer Research, and Website Development." No specific information requests were asked and no cross-examination was conducted regarding these specific programs, although Mr. Tremblay did cover their benefits at a high level at Tr. p.2956. Each of these programs relates to the increased need to communicate with TransAlta's customers during the transition to a new industry structure. TransAlta submitted that the programs are a prudent, cost effective way for TransAlta to discharge its obligation to keep its customers informed of industry change and should therefore be approved.

Board Findings

The Board agrees with TransAlta that it is important to communicate with customers during the transition to a new industry structure. However, the Board also agrees with the FIRM Customers that ratepayers should not fund marketing expenses primarily benefiting TransAlta's future retail activities. The Board considers that a portion of TransAlta's advertising and marketing costs will benefit TransAlta's future retail activities and are not required to communicate with customers during the transition to the new industry structure. The Board considers it would be fair and reasonable to allow approximately 50% of the advertising and marketing program costs in the revenue requirement as being beneficial to ratepayers. Accordingly, the Board will allow advertising and marketing expense costs of $0.45 million in 1999 and $0.65 million in 2000. The Board directs TransAlta, in its refiling, to reduce its forecast advertising and marketing expense by $450,000 in 1999 and $650,000 in 2000.

(4) Bad Debt Expense

Position of the FIRM Customers

TransAlta forecast bad debt expenses of $1.4 million for each of 1999 and 2000. This compares with recorded bad debts expenses of $2.0 million and $1.6 million for 1996 and 1997 respectively. Recorded bad debt expenses for 1998 were significantly lower at $0.9 million. In CCA.TAU-43(c), TransAlta stated bad debts "are trended based on total receivables."

[675] Tr. p.2958

The 1998 reduction was achieved as a result of "changes in collection processes" described in CCA.TAU-43(a) and testified to by Mr. Millar as follows:

> The one-time changes were primarily that in 1998–and again, this came into effect when we were reviewing and recentralizing our customer handling processes–we did review the bad debt expense and a number of bad debt accounts, and through our centralized processes, ***we were actually able to recover some bad debt that had already been assumed to be written off.***
>
> So we saw that as a definite one-time impact. We made an adjustment for it, and we have also reflected in 1999 and 2000 our forecast of the new base line. So we adjusted for what we saw as a one-time effect of collecting bad debt that had already been written off from our point of view, and then moved forward at the new, reasonable estimation.[676] (Emphasis added)

Even after reflecting the "new base line," TransAlta's 1999 and 2000 forecast for bad debts expense is strikingly close to the 1997 actual bad debts of $1.6 million. There has been no evidence adduced in these proceedings to suggest the level of bad debts will increase in the test years 1999/00. The FIRM Customers questioned whether TransAlta had adequately recognized the more efficient collections achieved as a result of its "centralized processes" in establishing its forecast for bad debts expenses in the test years.

The FIRM Customers noted that as a result of the "changes in collection processes" and the "centralized processes," TransAlta was able to recover some portion of the bad debts previously written off. To this end, the FIRM Customers submitted it is equally plausible that a certain portion of the accounts written off to the end of 2000 will also be similarly recovered. The FIRM Customers noted TransAlta effected a $0.9 million adjustment to the bad debts expense in 1998 – this is a reduction of $0.9 million (or 50%) from the $1.8 million average bad debts expense forecast for 1996 and 1997. Assuming that this recovery reflects bad debts accumulated over a five-year period the annual additional recovery would be $180,000.

The FIRM Customers recommended that the bad debts expense forecast for 1999 and 2000 be reduced by $200,000 in each year to reflect the recent experience in collections.

Position of TransAlta

TransAlta noted Mr. Millar's testimony that bad debt expense is forecast based on historical experience. Bad debts older than six months are rarely successfully collected, but the bad debt account is not closed for a period of five years. In 1998, with the implementation of new collection processes made possible through centralized customer handling, TransAlta not only improved its collection record, making possible the reduction in bad debt expense from the 1996

[676] Tr. p.2989-2990

and 1997 levels to $1.4 million, but also saw the one-time impact of successful attempts to recover several accounts outstanding from previous years.[677]

The improvement achieved in 1998 was a one-time improvement made possible by the implementation of the new collection process. TransAlta submitted that it is unreasonable to suggest that the new collection process should continue to result in further improvements of the same magnitude as 1998 and accordingly, TransAlta submitted that the Board should approve the bad debt expense as filed.

Board Findings

The Board agrees with the argument of the FIRM Customers that it would be reasonable to assume that the one-time collection of $0.9 million in 1998 would have accumulated over a five-year period at approximately $180,000 per year. The Board notes that the proposed $1.4 million bad debt expense is $200,000 less than the 1996 bad debt expense. The Board considers that TransAlta has appropriately included the recent experience improvement in the forecast of the new base line for 1999 and 2000. Accordingly, the Board approves the proposed $1.4 million bad debt expense for 1999 and 2000.

(5) Taxes other than Income

TransAlta forecast taxes other than income of $9.1 million for 1999 and $9.2 million for 2000 for the DISCO business unit.

Position of ENMAX

ENMAX proposed a global adjustment to the total GENCO, TRANSCO and DISCO property taxes.

ENMAX submitted that the Board should reduce the total amount allowed for taxes other than income taxes by $2 million for each of 1999 and 2000 to reflect current trends. ENMAX suggested that the forecast should not include increases that will not materialize.

Position of TransAlta

TransAlta provided the following reasons in support of its forecast increase in property taxes:

> The recorded property tax for the period 1996 to 1998 is relatively constant. For 1999 and 2000, TransAlta is forecasting an increase in property tax based on discussions with many parties including the province and municipalities. While municipalities will not establish their final budgets and final mill rates until March-June of 1999 and 2000, our discussions indicate many forces increasing

[677] Tr. p.2989-2990

pressure on municipal funding requirements and forcing increased assessments and taxes. In addition, the Provincial Government's October 31,1998 implementation (for the 1999 tax year) of updated Linear Property Assessment rates (1994 Cost Tables) is forecast to result in an average increase in Linear Taxes of approximately three percent. The forecast increase in assessable Linear property will result in an equal, direct increase in education taxes of approximately three percent. The widely publicized, province wide movement by municipal governments to "market value assessment" methods for business and property taxes is forecast to maintain or reduce most residential taxes while increasing some residential taxes and increasing most commercial and business taxes. Our forecast indicates that most municipalities will increase assessments and will reduce some (but not all) mill rates resulting in an overall average net increase in our provincial municipal tax total. Due to the previously discussed factors, specific municipality by municipality mill rate or assessment forecasts were without merit so an overall average factor was assumed. Recent media coverage of municipal council meetings indicate that many municipalities will increase taxes significantly. The City of Calgary has widely publicized estimated 1999 increases between four and five percent. The City of Edmonton media coverage implies tax increases of approximately five percent. The Provincial Government's regulation revisions will increase Linear assessments (affecting most utility property) by approximately three percent. TransAlta assumed in our forecast that a minimal annual average increase will be achieved by working closely with the municipalities and the Provincial Government.[678]

TransAlta submitted that the ENMAX submission that taxes other that income be reduced by $2.0 million in each of 1999 and 2000 has not been supported by any credible evidence in this proceeding. Given the evidence on the record, TransAlta submitted that the Intervenor arguments with respect to property tax are without merit and ought to be rejected.

Board Findings

The Board notes that TransAlta proposed a total Utility forecast for GENCO, TRANSCO and DISCO of $45.2 million in 1999 and $45.7 million in 2000 for taxes other than income. These figures included $1.0 million in 1999 and $1.1 million in 2000 for water rentals. The Board notes that the $2.0 million reduction proposed by ENMAX for the combined business units translates into an approximate 4.5% reduction to TransAlta's forecast excluding water rentals.

The Board has reviewed TransAlta's reasons for the forecast increase for taxes other than income tax. In view of those reasons, the Board considers that it would be reasonable to limit the forecast increase to no more than 5% for each business unit for 1999 over 1998 and no more than a further 1.5% increase for 2000 over 1999. Accordingly, the Board rejects the ENMAX proposal to reduce each of GENCO, TRANSCO and DISCO by 4.5%.

[678] ENMAX.TAU-40

The Board notes that TransAlta is proposing a 7% increase to DISCO property tax for 1999 and a further 1.5% increase for 2000. The Board considers that TransAlta's forecast increase should be limited to 5% for 1999 and a further 1.5% in 2000. Accordingly, the Board approves a DISCO forecast of $8.9 million for 1999 and $9.0 million for 2000 for taxes other than income which is a reduction of $300,000 for 1999 and $200,000 for 2000 from the forecast proposed by TransAlta. Therefore the Board directs TransAlta, in its refiling, to reduce DISCO taxes other than income by $300,000 for 1999 and $200,000 for 2000.

(6) Cash Operating Expense Summary

The Board notes that during the course of the proceedings a number of errors and omissions in TransAlta's original filing were identified. TransAlta listed these errors and omissions in Exhibits 59, 75 and 169.

Accordingly, the Board directs TransAlta, in its refiling of DISCO cash operating expenses, to incorporate all the errors and omissions identified in Exhibits 59, 75 and 169 as well as the Board approved reductions to corporate services costs and operating labour, advertising expense and taxes other than income.

(c) Income Tax

TransAlta stated that income taxes are now calculated separately for DISCO. TransAlta's prior practice was to calculate income taxes on a corporate basis and allocate the result to generation, transmission and distribution. All actual cumulative timing differences including capital cost allowance are directly assigned to each function.[679]

For DISCO TransAlta included, in its Application, a forecast income tax of $50.1 million for 1999 and $50.9 million for 2000.[680]

Board Findings

For purposes of this Decision, the Board approves the method, set out in Part 4–TAU, Section 1(f), Income Tax of this Decision, to calculate the component of revenue requirement attributable to income taxes for DISCO. The Board directs TransAlta, in its refiling, to provide detailed calculations for the recalculated income taxes to DISCO using the approved method described in the section noted above.

[679] Application Section 6.2
[680] Exhibit 59

(d) Quality of Service

Quality of service and electric reliability is an important aspect of utility service. Reliable power and good customer service promote economic growth and add to the quality of life.

Service quality can encompass many areas, such as Call Centre response, performance of field service personnel, billing and collections policies (including accuracy as well as availability of in-person payment stations), and complaint processing. Reliability issues include both frequency and duration of outages, as well as response to notification of outages and hazards.

Position of FIRM Customers

The FIRM Customers noted that cost-cutting pressures can lead to deterioration of utility performance. The FIRM Customers submitted that the Board should monitor aspects of customer service and reliability at this point in time to prevent such deterioration and to support customer service improvements where appropriate. The FIRM Customers noted that regulatory commissions in some North American jurisdictions have even implemented standards addressing aspects of electric service reliability and quality of service.[681] The FIRM Customers also noted that should alternative ratemaking structures be contemplated later in Alberta (e.g., performance-based ratemaking), it may be essential to develop and stipulate standards to prevent a decline in service quality. The FIRM Customers suggested that, in the interim, relevant data should be collected to enable the Board to take further action when, and if, required.

The FIRM Customers observed that some aspects of TransAlta's service quality were examined through the hearing process. Based on that review, it appears TransAlta currently has some methods in place for monitoring customer service and reliability.[682] These include:

- a customer satisfaction questionnaire,
- indices of system reliability,
- pre-determined response plans for hazard calls, and
- the monitoring of employee safety.

However, in other areas, improvements in performance and data collection would be desirable. In particular:

---

[681] For example, as part of their performance-based ratemaking mechanisms, some California Utilities are monitored on reliability indices, customer satisfaction surveys, call centre responsiveness, and service guarantees. [e.g., California Public Utilities Commission D.96-09-092 (for Southern California Edison Co.) and D.99-05-030 (for San Diego Gas & Electric Co.] In addition to those indicators, two merged Washington Utilities are monitored on complaints, safety response, missed appointments, and disconnects. [e.g., Washington Utilities and Transportation Commission Stipulation in Docket UE-960195 and New York Public Service Commission Case 96-E-0979 and preceding decisions]

[682] FIRM.TAU-106; FIRM.TAU-113; FIRM.TAU-108; FIRM.TAU-109

- Through mid-December, 1998 the call centre did not meet its goals to answer 80% of calls within 20 seconds and for fewer than five per cent of calls to be abandoned;[683]
- TransAlta does not record the number and percentage of appointments missed by field service representatives;[684]
- TransAlta does not record the number of customers whose service it disconnects in error; and[685]
- Estimated bills increased from 5% in 1996 through September, 1998, to 40% after September, 1998.[686]

Based on the foregoing, the FIRM Customers submitted the Board should direct TransAlta to continue gathering and monitoring indices of reliability. The Board should also encourage TransAlta to set and meet goals in the Call Centre and to gather data on missed field appointments and customers whose service is disconnected in error.

Position of the First Nations

The First Nations agreed with the FIRM Customers and suggested that the first step to good customer service is customer contact or consultation. The First Nations admitted that this contact is not always easy but maintained it is paramount in order to achieve "reliable power and good customer service" that will "promote economic growth" for First Nations and the Utilities and to reduce costs for all customers.

The First Nations requested that the Board direct the Utilities to actively engage in consultations with First Nations. These consultations could be with respect to service questions, rights of ways negotiations, contracts for Rights of Way clearing, new power generation projects, wire ownership, call center alternatives, procedures for disconnects reconnects and work with bands to establish processes that would facilitate these procedures and reduce costs.

Position of TransAlta

TransAlta responded to the argument of the First Nations by submitting that the steps it has taken demonstrates that TransAlta has already made considerable efforts to consult with the Aboriginal community regarding a number of issues and continues to proactively co-operate with First Nations groups. Accordingly, TransAlta submitted that there was no need for the direction sought by the First Nations.

TransAlta did not respond to the above argument of the FIRM Customers. However, TransAlta did make the following points during cross-examination:

---

[683] FIRM.TAU-104
[684] FIRM.TAU-105
[685] FIRM.TAU-107
[686] FIRM.TAU-110

- TransAlta stated that it is currently undertaking to measure the accuracy of completing appointments and service orders with their centralized dispatch and scheduling operation.[687]
- TransAlta disagreed that the increase in estimated bills from 5 percent to 40 percent was a reduction in quality of service. TransAlta considered that the customer bills being estimated are very predictable, are not volatile and do not vary much over time. TransAlta stated that it is improving service, because costs are being lowered while maintaining the integrity of the customer's bill. TransAlta stated that costs have reduced by about $200,000 as a result of estimating more customer bills.[688]

Board Findings

The Board agrees that customer contact and consultation is important. The Board notes TransAlta's efforts in this regard and expects TransAlta to continue to proactively consult with its customers.

The Board considers it important to ensure that there are adequate measures in place to monitor the quality of service especially as the industry moves through a restructuring phase. During the current restructuring of the electric industry some aspects of customer service may become strained as Utilities change the familiar processes to new ones. The Board notes that TransAlta's Call Centre is the result of a reorganization of field offices that handled customer calls in the past. The Board considers that it is not unusual to encounter some difficulties during the start up period. In respect of the recording of the number and percentage of appointments missed, the Board notes TransAlta's response, at Tr. p.2674, that recording of these statistics is now underway.

The Board acknowledges the need for improvements in performance and data collection and expects TransAlta will put in place the appropriate procedures to record relevant data to measure customer service performance in the restructured electric industry. The Board also acknowledges that some of the needed measurements or data may not be obvious at this time.

Notwithstanding the above, the Board considers it important to make a start at recording and measuring customer service performance. Accordingly, the Board directs TransAlta to collect the following quality of service data and provide an annual report to the Board and interested parties:

- Results of customer satisfaction questionnaires
- Indices of system reliability
- Response to notification of outages and hazards
- Call Center goals and statistics
- Field appointment statistics including missed appointments

[687] Tr. p.2674
[688] Tr. p.2675

- Customer connect and disconnect statistics including disconnect errors
- Meter reading frequency and accuracy statistics
- Billing and collection accuracy
- Customer complaints
- Employee safety statistics

The annual report should be submitted no later than 31 March in respect of the previous year's operations and should also set out TransAlta's plans to address any quality of service deficiencies.[689]

(e) Revenues

(1) Energy Sales and Revenues

TransAlta summarized the method used to forecast energy sales and revenues as follows:

> Forecasts were made for each revenue category based on historical data and information, macro-economic forecasts of factors affecting population growth and industrial production, and discussions of large customers with TransAlta sales representatives.
>
> Current estimates for 1998 reflect our expectations as of August, 1998 when the 1999-2000 forecast was prepared. Revenues are based on existing customer rates.

TAU ENERGY SALES AND REVENUES, 1999-2000.

- TAU total energy sales increase to 23,801 GWh in 1999, 3.2% higher than our 1998 current estimate, and then decline slightly to 23,742 GWh in 2000.
- TAU revenues increase to $1.222 Billion, 4.1% higher than our 1998 current estimate, and then decline slightly to $1.214 Billion in 2000.
- TAU peak demand is 3350 MW in December, 1999 and declines slightly to 3325 MW in December, 2000 as a result of load loss related to self-generation at some Chemical Plants.
- Pool prices are forecast to average $38.05/MWh in 1999 which is 18% higher than our 1998 forecast of $32.21/MWh. Pool prices are forecast to decline to $30.80/MWh in 2000.
- Economic growth in Alberta over the forecast period is expected to increase at a rate consistent with the past ten-year average following a period of above average growth in 1997 and 1998.
- Slightly improving but relatively soft commodity prices are assumed over the forecast period.

[689] Tr. p.2677

- The revenue forecast includes the impact of the $2.50/MWh rate reduction for customers on temporary energy as a result of the 1998 Negotiated Settlement.
- Total year-end customers are forecast to increase to approximately 367,500 in 1999 and 375,550 in 2000, incremental increases of some 7800 and 8050 customers respectively.[690]

TransAlta forecast load and revenues lost to self-generation as follows:

	1999		2000	
	Load (GWh)	Revenues ($Millions)	Load (GWh)	Revenues ($Millions)
Gas Processing and Refineries (Oil and Gas)	409.4	12.65	469.7	14.16
Chemical Plants (Other Industrial)	82.3	2.49	916.6	29.33
Total	**491.7**	**15.14**	**1,386.3**	**43.49**

TransAlta stated that the loss of load in the distribution forecast due to IPP generation was included in the IPP generation assumptions in the production modeling runs.[691] TransAlta stated that none of the load loss due to cogeneration projects were forecast to require standby service, and accordingly no standby revenue in respect of these services was included in the revenue forecast.[692]

The following table sets out the details of the forecast of the number of customers, energy sales and revenues by broad customer classification excluding the above noted losses to self-generation. TransAlta calculated revenues using existing rates rather than the rates proposed in the 1996 Phase II Application.[693]

[690] TransAlta Evidence, Section 4.4, p.1
[691] SPPA.TAU-1
[692] Exhibit 155
[693] Tr. p.2238

4. DISCO
(e) Revenues

Category		1996	1997	1998	1999	2000
Retail	No. of Cust	260,249	267,736	278,096	285,106	292,327
	Sales (GWh)	3,955.8	4,007.8	4,128.0	4,246.8	4,346.1
	Rev ($000)	350,041	354,924	364,984	374,822	383,506
Small Wholesale	No. of Cust	6	6	6	6	6
	Sales (GWh)	105.4	103.8	105.9	105.7	106.0
	Rev ($000)	5,014	4,897	4,956	4,955	4,965
TA Company Use	No. of Cust	49	49	54	54	54
	Sales (GWh)	176.8	182.2	184.0	185.2	185.9
	Rev ($000)	9,566	9,780	9,559	9,893	9,426
Farms	No. of Cust	67,019	60,542	61,127	61,513	61,926
	Sales (GWh)	1,311.4	1,315.5	1,246.2	1,277.8	1,289.7
	Rev ($000)	99,247	98,385	90,112	92,166	93,271
Oil &Gas	No. of Cust	18,544	18,899	19,576	19,987	20,398
	Sales (GWh)	9,662.8	9,985.2	10,571.5	10,795.7	11,155.1
	Rev ($000)	387,049	411,825	452,822	467,381	474,744
Other Industrial	No. of Cust	790	806	829	841	854
	Sales (GWh)	6,565.4	6,815.9	6,828.1	7,190.1	6,659.5
	Rev ($000)	226,975	235,920	251,465	272,987	247,895
Industrial	No. of Cust	19,334	19,705	20,405	20,828	21,252
	Sales (GWh)	16,228.2	16,801.1	17,399.6	17,985.8	17,814.6
	Rev ($000)	614,024	647,745	704,287	740,368	722,639
Total	No. of Cust	346,657	348,038	359,688	367,507	375,565
	Sales (GWh)	21,777.6	22,410.4	23,063.7	23,801.3	23,742.3
	Rev ($000)	1,077,892	1,115,731	1,173,898	**1,222,204**	**1,213,807**

TransAlta noted that no unbilled energy and revenue was included in the above table. TransAlta also noted that there was no loss of load or revenue in the forecast due to customers switching to direct access.

TransAlta stated that historical energy growth rates were not temperature normalized after the fact. In terms of forecast energy growth rates, TransAlta assumed normal temperatures and projected energy sales based on historical averages by revenue category. TransAlta submitted that five-year historical averages are a proxy for temperature normalization as applied to forecast energy growth rates.[694]

Board Findings

The Board has reviewed the forecast of revenues for 1999 and 2000 and is satisfied that the forecasts are reasonable. The Board has addressed the matter of unbilled revenue in the following section of this Decision. The Board considers that the difference in revenue resulting

[694] SPPA.TAU-1; Exhibit 134

from customers switching from a firm rate to a direct access rate would not be material for the test years. The Board accepts, as reasonable, TransAlta's forecast of the loss of load and revenues from customers forecast to self-generate.

The Board notes that TransAlta was directed to remove revenues in the amount of $200,000 in 1999 and $400,000 in 2000 as a result of the Board's findings in the DISCO capital additions section of this Decision. The Board notes that Intervenors did not raise any further issues respecting the revenue forecast. Accordingly, the Board approves forecast revenues at existing rates for TransAlta as follows:

TransAlta Forecast Revenues Board Approved	
1999 Forecast Revenues:	$1,222,004,000
2000 Forecast Revenues:	$1,213,407,000

The Board directs TransAlta, in its refiling, to incorporate any other consequential changes to the above revenues arising from the Board's findings in this Decision. The Board approves the remaining forecast revenues.

The Board considers that TransAlta's method of using a five-year historical average as a proxy for temperature normalization could be improved. The Board recognizes that customer choice may eliminate much of the need for temperature normalization. Nevertheless, the Board, directs TransAlta, at the time of the Regulated Rate Option Application or the next DISCO GTA, to report on improved methods of temperature normalizing energy sales for those customers who choose to remain on the regulated rate option.

(2) Unbilled Revenue

TransAlta summarized its position respecting unbilled revenues as follows:

> For financial accounting purposes, TransAlta records electric revenue on an accrual basis including unbilled revenue. For regulatory purposes, TransAlta's electric revenue in a given test year is forecast on a billed basis excluding unbilled revenue.
>
> TransAlta's forecast of distribution revenue for each of the 1999 and 2000 test years includes 12 months of billed consumption which is consistent with prior test years and does not include unbilled revenue. An adjustment was made to the revenue lag in the lead-lag study to provide the benefits of the funds associated with unbilled consumption to customers.

Unbilled revenue results primarily from cycle billings to residential, farm, commercial and some oilfield customers. Since most of these customers are expected to be eligible for the regulated Stable Rate Option, TransAlta does not expect a significant change in unbilled revenue between 2000 and 2001. In the event that this is not the case, TransAlta will propose an appropriate method of refunding of any significant difference at the time of the next GRA for TransAlta's distribution function.[695]

Board Findings

The Board notes that TransAlta's description and treatment of unbilled revenue is consistent with prior Board Decisions with respect to this issue. The Board accepts TransAlta's proposal, as reasonable, to deal with any significant change in unbilled revenue between 2000 and 2001 at a future DISCO Application. Accordingly, the Board directs TransAlta to address the issue of unbilled revenues, including a proposal to dispose of the funds associated with unbilled consumption under a customer choice environment, at the time of the Regulated Rate Option Application or the next DISCO GTA.

(f) Revenue Surplus/Deficiency

TransAlta, in their initial evidence, filed the following table illustrating their forecast revenue deficiency for the years 1999 and 2000:

($ million)

Category	1998F	1999F	2000F
Power Purchase Costs	660.3	707.1	707.0
Transmission Tariffs	216.7	252.8	248.8
Other Power Pool and Transmission Administrator Expenses	0.5	0.6	0.6
Cash Operating Expenses	94.2	102.6	105.1
Depreciation and Amortization	71 .1	85.6	89.2
Income Taxes	26.2	41.2	41.5
Total Return	41.9	45.1	42.0
Total Cost of Service	1,110.7	1,234.9	1,234.2
Electric Revenue at existing rates	1,116.8	1,179.1	1,170.5
Revenue (Surplus)/Deficiency	**(6.1)**	**55.8**	**63.7**

Source: TransAlta Evidence Section 4.1

[695] Exhibit 153

The Board notes that during the course of the proceedings a number of errors and omissions in TransAlta's original filing were identified. TransAlta listed these errors and omissions in Exhibits 59, 75 and 169.

Accordingly, the Board directs TransAlta, in its refiling, to incorporate all the errors and omissions identified in Exhibits 59, 75 and 169 as well as the changes to expense and revenues approved and directed in this Decision.

The Board also directs TransAlta, in its refiling, to propose a method of refunding any surplus or collecting any shortfall resulting from the refiled expenses and revenues.

(g) Customer Deposits

TransAlta's approved Terms and Conditions of service state that customer deposits are collected from customers when temporary service is requested, when new service is requested from a customer previously disconnected for non-payment or when the customer who is making application for service has an unsatisfactory credit rating.

Position of the FIRM Customers

The FIRM Customers noted that, for 1999 and 2000, TransAlta forecast it would collect $2.25 million in customer deposits. These amounts represent significant increases from the 1996 and 1997 actual amounts of $905,000 and $1.4 million, respectively. For accounting purposes, these deposits are considered a current liability. For regulatory purposes, "customer deposits have not been historically, are not currently, considered to be part of no cost capital as the deposit account accrues interest on the outstanding balance each month."[696]

Under TransAlta's Terms and Conditions of Service, a security deposit is eventually refunded, with interest, after 12 months if the customer's payment record is satisfactory. Interest is calculated "on a rate quoted by the Royal Bank of Canada for daily interest savings accounts."[697] Draw down of this amount occurs if the customer's service is disconnected for non-payment. What the current Terms and Conditions do not indicate is whether customers with poor payment records during the first twelve months ever become eligible for a refund of their deposits.

Because of the foregoing policy, TransAlta is given the opportunity of using customer-provided funds for at least twelve months, less interest at the extremely low, daily savings account rate. The interest on a daily interest savings account is almost negligible. The FIRM Customers submitted that the amounts collected with respect to customer deposits should be treated as no

[696] CCA.TAU-42e
[697] Section 10

cost capital.[698] Payments from this account would still be consistent with Board approved Terms and Conditions, including the payment of interest.

The FIRM Customers considered that since the vast majority of these deposits relate to residential and small business customers, these amounts should be allocated to the Distribution function's portion of no cost capital.

The FIRM Customers recommended that in order to determine the appropriate amount of mid-year no cost capital, TransAlta should be directed, in its refiling, to provide the cumulative amounts of customer deposits collected as at year end 1998, 1999 and 2000.

Position of TransAlta

In respect of the increase in customer deposits for 1999 and 2000, TransAlta explained that centralizing its practices, which were previously more difficult to maintain consistently when TransAlta dealt with customers from the various local offices, primarily drove the increase in the collections.

TransAlta stated that it reviewed and standardized the process for assessing whether or not a customer deposit was appropriate and the process for refunding those customer deposits when the customer payment record was improved and developed a satisfactory credit history.[699]

TransAlta responded to the FIRM Customers concern that "the amounts collected with respect to customer deposits should be treated as no cost capital. Payments from this account would still be consistent with Board approved Terms and Conditions, including the payment of interest."[700] TransAlta indicated in CCA.TAU-43(e) that interest is accrued on the outstanding balance of customer deposits each month and is payable to customers when the deposits are refunded. For this reason, customer deposits have not been, and should not be, included in no cost capital.

Board Findings

The Board considers that customer deposits are for the purpose of providing some protection to the utility for non-payment of the customer's account. No cost capital, on the other hand, is comprised of customer supplied funds for utility expenses that will occur or have a probability of occurring in the future. In other words, the funds will eventually be used in the operation of the utility.

For customer deposits the funds will be used, including any accrued interest, to either be refunded to the customer that supplied the deposit or to pay for services provided to that specific

[698] A number of U.S. States, including Maryland, Arkansas and Nevada, have a long-standing practice of including customer deposits in the capital structure.

[699] Tr. p.2991-2992

[700] FIRM Customers, p.42

customer. In other words customer deposits are ultimately refunded or used to reduce bad debt expense.

The Board agrees with TransAlta that customer deposits should not be included in no cost capital. However, the Board agrees with the FIRM Customers that TransAlta has the use of considerable amounts of ongoing customer deposits at a modest rate on a short-term basis. The Board considers that these funds can be used in a similar manner to the use of funds from short-term debt.

The Board's practice has been to include the cost of short-term debt in the embedded cost of debt when the prudent financial policies of the utility result in short term debt becoming a permanent feature of the utility's capital structure. The Board considers that an ongoing amount of customer deposit funds should be regarded as a permanent feature of the company's financial structure.

Accordingly, the Board directs TransAlta, in its refiling, to include the mid year forecast amount in the customer deposits account together with the associated cost rate (i.e., a forecast of the annual average of the daily interest savings rate) in its calculation of the embedded cost of debt for each of the test years.

5. SUMMARY OF BOARD DIRECTIONS

This section is a summary[701] of Board directions to TransAlta in this part. The Directions in *italics* are to be complied with in the 1999 refilings. The remaining directions are to be complied with in the future or at the time of the next GTA.

1. The Board directs TransAlta, in its next GTA filing, to specify the anticipated useful life of any capital enhancements to software systems included in the application. [Section 1(a)(5)]

2. *Therefore, the Board directs TransAlta, in its refiling, to transfer the amounts of $1.5 million in 1999 and $1.4 million in 2000 in Corporate Office Expense to the forecast CWIP costs of the Calgary Master Plan for the respective years until such time as the asset is transferred from CWIP to rate base.* [Section 1(b)(2)]

3. *Accordingly, the Board directs TransAlta, in its refiling to:*
   - *utilize a forecast sale price of $11 million (the average of TransAlta's proposed $5 million and the net book value of $17 million);*
   - *apportion the forecast net loss of $6 million (i.e. $17 million minus $11 million) between land and buildings on the basis of the original cost of the land and the net book cost of the building;*
   - *charge the portion of the $6 million net loss attributable to buildings to accumulated depreciation. By charging the net loss to accumulated depreciation the loss will be spread over the remaining life of the account; and*
   - *use the High River Service Centre loss allocation factors to allocate the forecast loss to transmission and distribution.* [Section 1(b)(3)]

4. *Therefore, the Board directs TransAlta, in its refiling, to remove the $1.5 million capital costs for the Sustainable Development Project from rate base. Also, the Board directs TransAlta, in its refiling, to remove any related operating costs from the $2.7 million in 1999 and $2.8 million in 2000, forecast operating costs that are included in TransAlta's Corporate O&M costs for Sustainable Development.* [Section 1(b)(4)]

5. *Therefore the Board directs TransAlta, in its refiling, to reduce the SD Projects O&M forecast amounts for of $3.7 million in 1999 and $2.5 million in 2000 by 50% to $1.85 million in 1999 and $1.25 million in 2000.* [Section 1(b)(5)]

[701] This summary has been prepared for the convenience of all parties. The directions in the main body of the Decision shall prevail over this summary if there are any differences.

6. Therefore, the Board directs TransAlta and the REAs to resolve any software compatibility issues and establish methods and procedures to exchange digital mapping information. [Section 1(b)(6)]

7. The Board directs TransAlta, in exchange for REA system information, to supply the REAs with digital mapping information at no charge to the REAs, commencing immediately upon release of this Decision. [Section 1(b)(6)]

8. *Therefore, the Board directs TransAlta, in its refiling, to reduce the 1999 total telecommunications forecast of $9.4 million by $0.8 million as acknowledged by TransAlta for a revised 1999 forecast of $8.6 million.* [Section 1(c)(2)]

9. *Further the Board directs TransAlta, in its refiling, to calculate its 2000 forecast by adding 1.6% to the $8.6 million determined by the Board for 1999.* [Section 1(c)(2)]

10. *Accordingly, the Board directs TransAlta, in its refiling, to allocate the $112.5 million residual Corporate Services buildings on the same basis as Corporate Services operating costs with the exception of the HRSC which shall be allocated 29% Transmission and 71% Distribution in accordance with the Board's findings earlier in this Decision.* [Section 1(d)]

11. The Board directs TransAlta to comply with Board Direction G-7 and file the detailed study in its next GTA for both Corporate Services operating cost and Corporate Services property. The study is to include justifications that the methods chosen fairly functionalize and allocate costs to business units (including unregulated business units). [Section 1(d)]

12. *The Board directs TransAlta, in its refiling, to remove the incentive compensation amounts for in-scope employees as indicated in TransAlta's letter of 13 April 1999.* [Section 1(e)]

13. *Accordingly, the Board directs TransAlta, in its refiling.*
    - *Beginning in 1999, make the necessary adjustments in respect of its booked and unbooked federal deferred income tax balances to comply with the liability method, that is set out in the CICA Handbook section 3465.*
    - *Allocate temporary differences to functions based on the method used to allocate net plant assets and any related liabilities to generation, transmission and distribution business units.*
    - *Adjust the resulting booked and unbooked temporary differences in a manner that will provide for the future income tax liability that would otherwise have been recorded at 1 January 1999 to be equated with the booked deferred income tax balance at 31 December 1998 (refer to Exhibit 205).*

- *Calculate the federal income tax component of the revenue requirement in accordance with the liability method, and to continue to do so until the recorded future income tax liability has been discharged.*
- *Adjust the income tax rates used to include the proposed changes to the manufacturing and processing profits tax rate reduction as set out in Resolution 16 of the Federal Budget of 16 February 1999.*

[Section 1(f)(3)]

14. *The Board directs TransAlta, in its refiling, to provide the recalculated income tax using the same format as set out in Appendices 6 and 7 as a supplement to the normal income tax schedules.* [Section 1(f)(3)]

15. Accordingly, the Board directs TransAlta to transfer any positive or negative balance in the Hearing Cost Reserve at the end of 2000 to the TRANSCO and DISCO functions and report on the transfers at the next GTA for TRANSCO and DISCO. [Section 1(g)]

16. *Accordingly, the Board directs TransAlta, in its refiling, to transfer $6.5 million from the DC liability reserve to the DB liability reserve.* [Section 1(h)]

17. *Accordingly, the Board directs TransAlta, in its refiling, to only include the effect of an additional 2% payment for employee contributions for the pension expense, pension contributions and pension liability for the pension plans as well as consequential effects on operating expenses and capital expenditures by business unit. The Board notes that TransAlta is free to maintain the full 4% benefit through shareholder funding if it so chooses.* [Section 1(h)]

18. *The Board directs TransAlta, in its refiling, to remove the effect of the additional 8% one-time increase to pension benefits from the pension expense, pension contributions and pension liability for the pension plans as well as consequential effects on operating expenses and capital expenditures by business unit. The Board notes that TransAlta is free to maintain this benefit through shareholder funding if it so chooses.* [Section 1(h)

19. *The Board directs TransAlta, in its refiling, to remove the additional commercial insurance premiums of $6.1 million and reinstate the self-insurance reserve.* [Section 1(i)]

20. Therefore, the Board directs TransAlta, if it wishes to claim for UOV payments, to use the TSR mechanism rather than the self-insurance reserve. [Section 1(i)]

21. The Board directs TransAlta, in any application for a TSR, to include adjustments, similar in methodology, as the Board directed AE to include in the section of this Decision dealing with AE's Reserve for Injuries and Damages. [Section 1(i)]

22. The Board directs TransAlta to apply to the Board for final disposal of the closing balance of the self-insurance reserve as at 31 December 2000. At the time of the

application, the Board will review the charges to the self-insurance reserve and approve the disposition of any remaining balances to the Balancing Pool. [Section 1(i)]

23. *The Board directs TransAlta, in its refiling, to recalculate the annual depreciation provision and accumulated depreciation for each of GENCO, TRANSCO and DISCO incorporating the following:*
    - *The depreciation related errors and corrections identified by TransAlta.*
    - *The forecast net proceeds for the High River Service Centre approved by the Board in the Corporate Capital Additions Part 4-TAU, Section 1(b)(3) of this Decision.*
    - *The actual recorded opening plant balances as of 1 January 1999.*
    - *The forecast capital additions for 1999 and 2000 approved by the Board in this Decision.*
    - *Changes made to coal amortization as determined in Part 4-TAU, Section 2(c)(1) of this Decision.* [Section 1(j)]

24. *Therefore, the Board directs TransAlta, in its refiling, to remove the Highvale Ash Hauler project from the year 1999 rate base and include this expenditure in the year 2000 rate base.* [Section 2(a)(1)(B)]

25. *The Board directs TransAlta, in its refiling, to remove the Sundance 1-4 Secondary Crusher project from the year 1999 rate base and include it in the year 2000 rate base.* [Section 2(a)(1)(E)]

26. *In view of the uncertainty, the Board directs TransAlta, in its refiling, to remove the Sundance Water Treatment Plant project from the year 1999 rate base and include it in the year 2000 rate base.* [Section 2(a)(1)(H)]

27. *Therefore, the Board directs TransAlta, in its refiling, to remove the rate base capatilization of the Highvale Mine Shop during the test period and ensure that any expenditures on this project during the test period be held in CWIP pending inclusion in rate base through the PPA process.* [Section 2(a)(1)(K)]

28. *The Board directs TransAlta, in its refiling, to reduce the proposed Spray Woodstave Pipeline project capital expenditures by $1,850,000 in 2000.* [Section 2(a)(1)(N)]

29. *The Board directs TransAlta, in its refiling, to reduce the proposed Hydro Maintenance Services project capital expenditures by $1,450,000 in 2000.* [Section 2(a)(1)(O)]

30. *The Board directs TransAlta, in its refiling, to remove $8.2 million of capital additions from the projects costing less than $1.0 million.* [Section 2(a)(1)(W)]

31. *The Board directs TransAlta, in its refiling, to revise the 1999 and 2000 NWC using the Board approved costs in each expense category.* [Section 2(a)(2)]

5. SUMMARY OF BOARD DIRECTIONS

32. *Therefore the Board directs TransAlta, in its refiling, to remove incentive compensation in the amount of $1.7 million for GENCO ($0.3 million), TRANSCO ($0.5 million) and DISCO ($0.9 million) as well as any amount included in the Corporate Services forecast for in-scope incentive compensation in 1999 and 2000.* [Section 2(b)(2)(C)]

33. *The Board directs TransAlta, in its refiling, to remove the proposed $9.6 million amortization of the costs of excess outside coal rights from the test years.* [Section 2(c)(1)]

34. *Accordingly, the Board directs TransAlta, in its refiling, to make a choice of one of the following options and to advise the Board at the time of refiling which of the four options it chooses:*

- *Option 1: Retain the current regulatory treatment for the period 1999-2000 and deal with the post 1 January 2001 period within the IAT and the PPA process. The Board directs, TransAlta, in its refiling, to reflect the same regulatory treatment on these assets in 1999 and 2000 as was in place during 1998.*
- *Option 2: Commit to transfer the excess coal rights to a non-regulated affiliate of TransAlta at a transfer price of $9.6 million prior to 31 December 2000. The Board directs TransAlta, in its refiling, to remove the $9.6 million from rate base effective 1 January 1999. The Board directs TransAlta, under Option 2, to transfer the excess outside coal rights to an unregulated affiliate prior to 31 December 2000.*
- *Option 3: Commit to gift the excess outside coal rights at no cost to the Province of Alberta as a proxy for Alberta electric consumers by 31 December 2000. The Board directs TransAlta, in its refiling, to include an amortization amount of $436,364 (i.e., $9.6 million/22 years) for each of 1999 and 2000. If Option 3 is attempted and can not be achieved, the Board would expect TransAlta to apply for an adjustment to the regulatory treatment approved in this Decision.*
- *Option 4: Commit to sell all rights and interests to an unrelated arms-length third party following a suitable auction process. The Board directs TransAlta, in its refiling, to include an amortization amount of $436,364 (i.e., $9.6 million/22 years) for each of 1999 and 2000. If Option 4 is attempted, and is either not successful or the transaction is not acceptable to the Board when approval for the actual disposition is applied for, then Option 3 would be acceptable to the Board. If Option 4 is successful, the Board, after consideration of an application by TransAlta, will approve an appropriate amount for net proceeds (after sale expenses). The Board will adjust the remaining $8.73 million amortization to be collected from the Balancing Pool and the annual payments from the Balancing Pool proportionately.* [Section 2(c)(1)(A)]

35. *The Board directs TransAlta, in its refiling, to remove the $4.012 million Excess Highvale Coal amortization from each of the test years.* [Section 2(c)(1)(B)]

36. *Accordingly, the Board directs TransAlta, in its refiling, to include an amortization amount of $182,364 (i.e. $4.012 million/22 years) for each of 1999 and 2000. The Board*

approves the recovery of the remaining amount of $3.64 million (i.e. $4.012 million less 1999/2000 amortization of $0.364 million) from the Balancing Pool over the period 2001 to 2020. [Section 2(c)(1)(B)]

37. *The Board directs TransAlta, in its refiling, to remove the requested Westmin 82 Take-or-Pay amortization of $3.93 million in 1999 and $4.25 million in 2000.* [Section 2(c)(1)(C)]

38. *Accordingly, the Board directs TransAlta, in its refiling to include an amortization amount of $178,636 (i.e. $3.93 million/22 years) for 1999 and $381,017 ($178,636 + $202,381 (i.e. $4.25 million/21 years)) for 2000.* [Section 2(c)(1)(C)]

39. *Accordingly, the Board directs TransAlta, in its refiling, to utilize a levelized reclamation cost of $0.524/tonne for the Highvale mine calculated as follows:*

• *Backlogged reclamation costs*	*$20.3 million*
• *Less existing reclamation reserve balance*	*$5.9 million*
• *Equals deficiency in past reclamation costs*	*$14.4 million*
• *Plus future reclamation costs*	*$105.7 million*
• *Plus expit costs from past disturbances*	*$8.3 million*
• *Equals net remaining reclamation costs*	*$128.4 million*
• *Divided by remaining tonnage to be mined*	*245 million tonnes*
• *Equals unit reclamation cost*	*$0.524/tonne*

[Section 2(c)(1)(D)]

40. *The Board directs TransAlta, in its refiling, to provide detailed calculations for the recalculated income taxes to GENCO using the approved method described in the section noted above.* [Section 2(d)]

41. *Accordingly, the Board agrees with the specific recommendations of the FIRM Customers set out above and the Board directs TransAlta, in its refiling, to follow those recommendations and reduce its revenue requirement by $8.808 million in 1999 and $9.031 million in 2000.* [Section 2(e)(1)]

42. *The Board directs TransAlta to apply to the Board for approval to transfer the balance remaining in the reserve for revenue adjustment claims at the end of the year 2000 to the Balancing Pool on 1 January 2001.* [Section 2(e)(1)]

43. *Therefore, the Board directs TransAlta, in its refiling to continue to calculate the claim for excess energy costs at the hourly pool price rather than at the contract price.* [Section 2(e)(2)]

44. *Accordingly, the Board directs TransAlta, in its refiling, to continue to use the above method to calculate the claim for excess energy costs.* [Section 2(e)(2)]

5. SUMMARY OF BOARD DIRECTIONS

45. *The Board directs TransAlta, in its refiling, to revise the 1999 and 2000 NWC using the Board approved costs in each expense category.* [Section 3(a)]

46. *The Board directs TransAlta, in its refiling, to provide detailed calculations for the recalculated income taxes to TRANSCO using the approved method described in the section noted above.* [Section 3(c)]

47. *Therefore, as a result of the above noted findings, the Board directs TransAlta, in its refiling, to remove the $2.5 million dollars for each of the years 1999 and 2000 forecast for oilfield metering installations.* [Section 4(a)(1)(B)]

48. Accordingly, the Board directs TransAlta to apply the same schedule of charges to its non-regulated affiliates effective 1 January 1999 as it charges the REAs or the market value whichever is higher. [Section 4(a)(1)(C)]

49. *Accordingly, the Board directs TransAlta, in its refiling, to remove the forecast DISCO capital additions of $2.9 million dollars for each of the years 1999 and 2000 for purchases of REAs and to remove the increase in revenues in the amount of $0.2 million in 1999 and $0.4 million in 2000.* [Section 4(a)(1)(C)]

50. *The Board directs TransAlta, in its refiling, to revise the 1999 and 2000 NWC using the Board approved costs in each expense category.* [Section 4(a)(3)]

51. *The Board directs TransAlta, in its refiling, to reduce its forecast advertising and marketing expense by $450,000 in 1999 and $650,000 in 2000.* [Section 4(b)(3)]

52. *Therefore the Board directs TransAlta, in its refiling, to reduce DISCO taxes other than income by $300,000 for 1999 and $200,000 for 2000.* [Section 4(b)(5)]

53. *Accordingly, the Board directs TransAlta, in its refiling of DISCO cash operating expenses, to incorporate all the errors and omissions identified in Exhibits 59, 75 and 169 as well as the Board approved reductions to corporate services costs and operating labour, advertising expense and taxes other than income.* [Section 4(b)(6)]

54. *The Board directs TransAlta, in its refiling, to provide detailed calculations for the recalculated income taxes to DISCO using the approved method described in the section noted above.* [Section 4(c)]

55. Accordingly, the Board directs TransAlta to collect the following quality of service data and provide an annual report to the Board and interested parties:
    - Results of customer satisfaction questionnaires
    - Indices of system reliability
    - Response to notification of outages and hazards
    - Call Center goals and statistics

- Field appointment statistics including missed appointments
- Customer connect and disconnect statistics including disconnect errors
- Meter reading frequency and accuracy statistics
- Billing and collection accuracy
- Customer complaints
- Employee safety statistics

The annual report should be submitted no later than 31 March in respect of the previous year's operations and should also set out TransAlta's plans to address any quality of service deficiencies. [Section 4(d)]

56. *The Board directs TransAlta, in its refiling, to incorporate any other consequential changes to the above revenues arising from the Board's findings in this Decision.* [Section 4(e)(1)]

57. Nevertheless, the Board, directs TransAlta, at the time of the Regulated Rate Option Application or the next DISCO GTA, to report on improved methods of temperature normalizing energy sales for those customers who choose to remain on the regulated rate option. [Section 4(e)(1)]

58. Accordingly, the Board directs TransAlta to address the issue of unbilled revenues, including a proposal to dispose of the funds associated with unbilled consumption under a customer choice environment, at the time of the Regulated Rate Option Application or the next DISCO GTA. [Section 4(e)(2)]

59. *Accordingly, the Board directs TransAlta, in its refiling, to incorporate all the errors and omissions identified in Exhibits 59, 75 and 169 as well as the changes to expense and revenues approved and directed in this Decision.* [Section 4(f)]

60. *The Board also directs TransAlta, in its refiling, to propose a method of refunding any surplus or collecting any shortfall resulting from the refiled expenses and revenues.* [Section 4(f)]

61. *Accordingly, the Board directs TransAlta, in its refiling, to include the mid year forecast amount in the customer deposits account together with the associated cost rate (i.e., a forecast of the annual average of the daily interest savings rate) in its calculation of the embedded cost of debt for each of the test years.* [Section 4(g)]

6. ORDER

THEREFORE, IT IS ORDERED THAT:

(1) TransAlta Utilities Corporation shall refile its 1999/2000 General Tariff Application, on or before 16 December 1999, incorporating the findings of the Board in this Decision respecting EPGI, EPTI, TransAlta and the AE Negotiated Settlement as approved in Decision U99046.

(2) TransAlta Utilities Corporation, in its refiling, shall include all of the supporting schedules necessary for the Board to makes its final determination respecting (i) TransAlta's 1999/2000 Phase I revenue requirement for its GENCO, TRANSCO and DISCO functions; (ii) 1999/2000 GENCO reservation prices and UOPs and (iii) 1999/2000 TRANSCO tariffs. The refiling shall be at a level of detail sufficient to reconcile with the original filing and demonstrate compliance with the Board's findings.

(3) TransAlta Utilities Corporation, in its refiling, shall identify the quantum of adjustments arising from differences between existing and final 1999 GENCO reservation prices and 1999 TRANSCO tariffs and propose a method of collecting or refunding the adjustments.

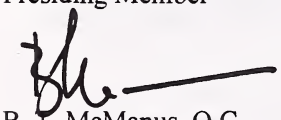
(4) TransAlta Utilities Corporation, in its refiling, shall identify the quantum of the 1999/2000 DISCO revenue surplus or shortfall using forecast revenues from existing approved rates and propose a method of refunding or collecting this surplus or shortfall to or from its customers.

Dated in Calgary, Alberta, on 25 November 1999.

ALBERTA ENERGY AND UTILITIES BOARD



N. W. MacDonald, P.Eng.
Presiding Member



B. T. McManus, Q.C.
Member



A. J. Berg, P.Eng.

APPENDICES 1-7

Appendix 1	ATWACC Modifications (14 pages)	823
Appendix 2	TransAlta Fair Return 1999 (4 Pages)	837
Appendix 3	TransAlta Fair Return 2000 (4 Pages)	841
Appendix 4	EPGI/EPTI Fair Return 1999 (2 Pages)	845
Appendix 5	EPGI/EPTI Fair Return 2000 (2 Pages)	847
Appendix 6	TransAlta 1999 Income Tax (2 Pages)	849
Appendix 7	TransAlta 2000 Income Tax (2 Pages)	851

Canadian Sample Companies / Source: Evidence of Dr. Vilbert MJV-3, Panels A-I

			($000)					
BC Gas Inc.		Book Ratios	Ave	1997	1996	1995	1994	1993
Book Equity		0.29	563,968	588,200	630,700	569,900	545,791	485,251
Preferred		0.07	150,000	150,000	150,000	150,000	150,000	150,000
Debt	Short		356,315	376,500	332,100	408,700	387,066	277,211
	Long		945,936	1,015,100	969,800	959,000	918,150	867,632
	Total	0.64	1,302,252					
		1.00	2,040,452					
Canadian Utilities		Book Ratios	Ave	1997	1996	1995	1994	1993
Book Equity		0.33	1,113,365	1,245,400	1195,900	1,109,800	1,032,300	983,427
Preferred		0.18	609,000	535,000	534,500	606,400	689,000	680,100
Debt	Short		0	0	0	0	0	0
	Long		1,610,620	1,844,000	1,792,500	1,809,400	1,324,800	1,282,400
	Total	0.48	1,610,620					
		1.00	3,332,985					
Fortis Inc.		Book Ratios	Ave	1997	1996	1995	1994	1993
Book Equity		0.40	286,942	326,543	309,851	294,698	274,787	228,829
Preferred		0.12	83,491	58,430	108,430	118,990	70,702	60,905
Debt	Short		42,202	46,433	54,210	36,858	51,926	21,582
	Long		306,992	400,688	338,325	297,197	274,388	224,363
	Total	0.49	349,194					
		1.00	719,627					
Gaz Metropolitain		Book Ratios	Ave	1997	1996	1995	1994	1993
Book Equity		0.46	690,131	732,148	734,903	730,329	654,415	598,861
Preferred		0.00	5,486	13,811	13,620	0	0	0
Debt	Short		22,107	44,760	20,982	17,951	18,652	8,188
	Long		787,226	832,041	840,385	848,767	795,181	619,755
	Total	0.54	809,332					
		1.00	1,504,950					
Nova Scotia Power		Book Ratios	Ave	1997	1996	1995	1994	1993
Book Equity		0.32	834,080	892,000	862,900	836,200	805,600	773,700
Preferred		0.08	200,000	200,000	200,000	200,000	200,000	200,000
Debt	Short		241,180	296,500	217,600	194,200	357,100	140,500
	Long		1,335,880	1,308,100	1,468,200	1,387,500	1,185,000	1,330,600
	Total	0.60	1,577,060					
		1.00	2,611,140					

Canadian Sample Companies (continued)

			($000)					
TransAlta Corp		Book Ratios	Ave	1997	1996	1995	1994	1993
Book Equity		0.39	1,542,380	1,594,300	1,582,300	1,542,700	1,515,000	1,477,600
Preferred		0.10	384,360	267,600	270,500	371,900	462,800	549,000
Debt	Short		19,300	41,600	16,600	0	38,300	0
	Long		1,980,860	2,198,000	2,364,000	2,009,000	1,584,500	1,748,800
	Total	0.51	2,000,160					
		1.00	3,926,900					
IPL Energy Inc.		Book Ratios	Ave	1997	1996	1995	1994	1993
Book Equity		0.26	1,020,120	1,699,400	1,396,000	1,095,600	446,400	463,200
Preferred		0.02	82,760	100,000	100,000	105,900	107,900	0
Debt	Short		118,360	165,200	258,900	167,700	0	0
	Long		2,672,560	3,475,800	2,931,100	2,671,300	3,540,400	744,200
	Total	0.72	2,790,920					
		1.00	3,893,800					
Pacific Northern		Book Ratios	Ave	1997	1996	1995	1994	1993
Book Equity		0.34	51,637	59,142	54,785	51,038	48,432	44,787
Preferred		0.06	9,504	13,609	18,910	5,000	5,000	5,000
Debt	Short		8,880	9,763	8,400	5,865	15,637	4,735
	Long		79,738	94,847	80,049	83,993	67,927	71,874
	Total	0.59	88,618					
		1.00	149,759					
Westcoast		Book Ratios	Ave	1997	1996	1995	1994	1993
Book Equity		0.25	1,656,200	2,056,000	1,890,000	1,542,000	1,448,000	1,345,000
Preferred		0.08	532,400	655,000	593,000	508,000	513,000	393,000
Debt	Short		326,400	266,000	41,000	375,000	568,000	382,000
	Long		4,159,000	5,090,000	4,817,000	4,679,000	3,290,000	2,919,000
	Total	0.67	4,485,400					
		1.00	6,674,000					

Canadian Sample Companies (continued) / Source: Evidence of Dr. Vilbert MJV-10, Panels A-J

(E/V = Market Equity to Value Ratio; P/V = Preferred Equity to Value Ratio; D/V = Market Debt to Value Ratio; I.T. = Income Tax Rate)
Cost rates shown for Equity, Preferred and Debt

Panel A

MARKET	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	BOOK	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	Market Minus Book Difference
BC Gas Inc.	9.8%	0.34	6.4%	0.06	6.1%	0.60	43.5%	5.8%	BC Gas Inc.	9.8%	0.29	6.4%	0.07	6.1%	0.64	43.5%	5.5%	
Canadian Utilities	10.5%	0.43	5.6%	0.15	6.0%	0.42	43.5%	6.8%	Canadian Utilities	10.5%	0.33	5.6%	0.18	6.0%	0.48	43.5%	6.2%	
Fortis Inc.	9.2%	0.44	5.5%	0.10	6.1%	0.46	43.5%	6.2%	Fortis Inc.	9.2%	0.40	5.5%	0.12	6.1%	0.49	43.5%	6.0%	
Gaz Met	9.3%	0.62	0.0%	0.00	6.1%	0.37	43.5%	7.0%	Gaz Met	9.3%	0.46	0.0%	0.00	6.1%	0.54	43.5%	6.1%	
Nova Scotia Power	9.5%	0.38	5.8%	0.07	6.1%	0.55	43.5%	5.9%	Nova Scotia Power	9.5%	0.32	5.8%	0.08	6.1%	0.60	43.5%	5.6%	
TransAlta Corp	9.7%	0.51	7.6%	0.08	6.0%	0.41	43.5%	6.9%	TransAlta Corp	9.7%	0.39	7.6%	0.10	6.0%	0.51	43.5%	6.3%	
IPL Energy Inc.	9.4%	0.45	5.9%	0.01	6.1%	0.54	43.5%	6.2%	IPL Energy Inc.	9.4%	0.26	5.9%	0.02	6.1%	0.72	43.5%	5.1%	
Pacific Northern	9.5%	0.43	6.5%	0.05	6.2%	0.53	43.5%	6.3%	Pacific Northern	9.5%	0.34	6.5%	0.06	6.2%	0.59	43.5%	5.8%	
Westcoast Energy	9.5%	0.30	5.8%	0.07	6.1%	0.63	43.5%	5.4%	Westcoast Energy	9.5%	0.25	5.8%	0.08	6.1%	0.67	43.5%	5.1%	
Elect Co. average	9.7%	0.44	6.1%	0.10	6.1%	0.46	43.5%	6.5%	Elect Co. average	9.7%	0.36	6.1%	0.12	6.1%	0.52	43.5%	6.0%	46
Average	9.6%	0.43	5.5%	0.07	6.1%	0.50	43.5%	6.3%	Average	9.6%	0.34	5.5%	0.08	6.1%	0.58	43.5%	5.7%	55

Panel B

MARKET	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	BOOK	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	Market Minus Book Difference
BC Gas Inc.	8.6%	0.34	6.4%	0.06	6.1%	0.60	43.5%	5.4%	BC Gas Inc.	8.6%	0.29	6.4%	0.07	6.1%	0.64	43.5%	5.1%	
Canadian Utilities	9.6%	0.43	5.6%	0.15	6.0%	0.42	43.5%	6.4%	Canadian Utilities	9.6%	0.33	5.6%	0.18	6.0%	0.48	43.5%	5.9%	
Fortis Inc.	7.6%	0.44	5.5%	0.10	6.1%	0.46	43.5%	5.5%	Fortis Inc.	7.6%	0.40	5.5%	0.12	6.1%	0.49	43.5%	5.3%	
Gaz Met	7.8%	0.62	0.0%	0.00	6.1%	0.37	43.5%	6.1%	Gaz Met	7.8%	0.46	0.0%	0.00	6.1%	0.54	43.5%	5.4%	
Nova Scotia Power	8.1%	0.38	5.8%	0.07	6.1%	0.55	43.5%	5.4%	Nova Scotia Power	8.1%	0.32	5.8%	0.08	6.1%	0.60	43.5%	5.1%	
TransAlta Corp	8.4%	0.51	7.6%	0.08	6.0%	0.41	43.5%	6.3%	TransAlta Corp	8.4%	0.39	7.6%	0.10	6.0%	0.51	43.5%	5.8%	
IPL Energy Inc.	8.0%	0.45	5.9%	0.01	6.1%	0.54	43.5%	5.5%	IPL Energy Inc.	8.0%	0.26	5.9%	0.02	6.1%	0.72	43.5%	4.7%	
Pacific Northern	8.2%	0.43	6.5%	0.05	6.2%	0.53	43.5%	5.7%	Pacific Northern	8.2%	0.34	6.5%	0.06	6.2%	0.59	43.5%	5.3%	
Westcoast Energy	8.1%	0.30	5.8%	0.07	6.1%	0.63	43.5%	5.0%	Westcoast Energy	8.1%	0.25	5.8%	0.08	6.1%	0.67	43.5%	4.8%	
Elect Co. average	8.4%	0.44	6.1%	0.10	6.1%	0.46	43.5%	5.9%	Elect Co. average	8.4%	0.36	6.1%	0.12	6.1%	0.52	43.5%	5.5%	36
Average	8.3%	0.43	5.5%	0.07	6.1%	0.50	43.5%	5.7%	Average	8.3%	0.34	5.5%	0.08	6.1%	0.58	43.5%	5.3%	42

Canadian Sample Companies (continued)

Panel C

MARKET	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	BOOK	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	Market Minus Book Difference
BC Gas Inc.	10.5%	0.34	6.4%	0.06	6.1%	0.60	43.5%	6.0%	BC Gas Inc.	10.5%	0.29	6.4%	0.07	6.1%	0.64	43.5%	5.7%	
Canadian Utilities	11.0%	0.43	5.6%	0.15	6.0%	0.42	43.5%	7.0%	Canadian Utilities	11.0%	0.33	5.6%	0.18	6.0%	0.48	43.5%	6.3%	
Fortis Inc.	10.0%	0.44	5.5%	0.10	6.1%	0.46	43.5%	6.5%	Fortis Inc.	10.0%	0.40	5.5%	0.12	6.1%	0.49	43.5%	6.3%	
Gaz Met	10.1%	0.62	0.0%	0.00	6.1%	0.37	43.5%	7.5%	Gaz Met	10.1%	0.46	0.0%	0.00	6.1%	0.54	43.5%	6.5%	
Nova Scotia Power	10.3%	0.38	5.8%	0.07	6.1%	0.55	43.5%	6.2%	Nova Scotia Power	10.3%	0.32	5.8%	0.08	6.1%	0.60	43.5%	5.8%	
TransAlta Corp	10.4%	0.51	7.6%	0.08	6.0%	0.41	43.5%	7.3%	TransAlta Corp	10.4%	0.39	7.6%	0.10	6.0%	0.51	43.5%	6.6%	
IPL Energy Inc.	10.2%	0.45	5.9%	0.01	6.1%	0.54	43.5%	6.5%	IPL Energy Inc.	10.2%	0.26	5.9%	0.02	6.1%	0.72	43.5%	5.3%	
Pacific Northern	10.3%	0.43	6.5%	0.05	6.2%	0.53	43.5%	6.6%	Pacific Northern	10.3%	0.34	6.5%	0.06	6.2%	0.59	43.5%	6.0%	
Westcoast Energy	10.3%	0.30	5.8%	0.07	6.1%	0.63	43.5%	5.7%	Westcoast Energy	10.3%	0.25	5.8%	0.08	6.1%	0.67	43.5%	5.3%	
Elect Co. average	10.4%	0.44	6.1%	0.10	6.1%	0.46	43.5%	6.8%	Elect Co. average	10.4%	0.36	6.1%	0.12	6.1%	0.52	43.5%	6.3%	51
Average	10.3%	0.43	5.5%	0.07	6.1%	0.50	43.5%	6.6%	Average	10.3%	0.34	5.5%	0.08	6.1%	0.58	43.5%	6.0%	62

Panel D

MARKET	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC		Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	Market Minus Book Difference
BC Gas Inc.	9.6%	0.34	6.4%	0.06	6.1%	0.60	43.5%	5.7%	BC Gas Inc.	9.6%	0.29	6.4%	0.07	6.1%	0.64	43.5%	5.4%	
Canadian Utilities	10.4%	0.43	5.6%	0.15	6.0%	0.42	43.5%	6.7%	Canadian Utilities	10.4%	0.33	5.6%	0.18	6.0%	0.48	43.5%	6.1%	
Fortis Inc.	8.9%	0.44	5.5%	0.10	6.1%	0.46	43.5%	6.1%	Fortis Inc.	8.9%	0.40	5.5%	0.12	6.1%	0.49	43.5%	5.9%	
Gaz Met	9.0%	0.62	0.0%	0.00	6.1%	0.37	43.5%	6.9%	Gaz Met	9.0%	0.46	0.0%	0.00	6.1%	0.54	43.5%	6.0%	
Nova Scotia Power	9.3%	0.38	5.8%	0.07	6.1%	0.55	43.5%	5.8%	Nova Scotia Power	9.3%	0.32	5.8%	0.08	6.1%	0.60	43.5%	5.5%	
TransAlta Corp	9.5%	0.51	7.6%	0.08	6.0%	0.41	43.5%	6.8%	TransAlta Corp	9.5%	0.39	7.6%	0.10	6.0%	0.51	43.5%	6.2%	
IPL Energy Inc.	9.2%	0.45	5.9%	0.01	6.1%	0.54	43.5%	6.1%	IPL Energy Inc.	9.2%	0.26	5.9%	0.02	6.1%	0.72	43.5%	5.0%	
Pacific Northern	9.3%	0.43	6.5%	0.05	6.2%	0.53	43.5%	6.2%	Pacific Northern	9.3%	0.34	6.5%	0.06	6.2%	0.59	43.5%	5.7%	
Westcoast Energy	9.3%	0.30	5.8%	0.07	6.1%	0.63	43.5%	5.4%	Westcoast Energy	9.3%	0.25	5.8%	0.08	6.1%	0.67	43.5%	5.1%	
Elect Co. average	9.5%	0.44	6.1%	0.10	6.1%	0.46	43.5%	6.4%	Elect Co. average	9.5%	0.36	6.1%	0.12	6.1%	0.52	43.5%	5.9%	44
Average	9.4%	0.43	5.5%	0.07	6.1%	0.50	43.5%	6.2%	Average	9.4%	0.34	5.5%	0.08	6.1%	0.58	43.5%	5.7%	53

Canadian Sample Companies (continued)

Panel E

MARKET	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	BOOK	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	Market Minus Book Difference
BC Gas Inc.	9.6%	0.34	6.4%	0.06	6.1%	0.60	43.5%	5.7%	BC Gas Inc.	9.8%	0.29	6.4%	0.07	6.1%	0.64	43.5%	5.5%	
Canadian Utilities	10.2%	0.43	5.6%	0.15	6.0%	0.42	43.5%	6.6%	Canadian Utilities	10.5%	0.33	5.6%	0.18	6.0%	0.48	43.5%	6.2%	
Fortis Inc.	9.0%	0.44	5.5%	0.10	6.1%	0.46	43.5%	6.1%	Fortis Inc.	9.2%	0.40	5.5%	0.12	6.1%	0.49	43.5%	6.0%	
Gaz Met	9.1%	0.62	0.0%	0.00	6.1%	0.37	43.5%	6.9%	Gaz Met	9.3%	0.46	0.0%	0.00	6.1%	0.54	43.5%	6.1%	
Nova Scotia Power	9.3%	0.38	5.8%	0.07	6.1%	0.55	43.5%	5.8%	Nova Scotia Power	9.5%	0.32	5.8%	0.08	6.1%	0.60	43.5%	5.6%	
TransAlta Corp	9.5%	0.51	7.6%	0.08	6.0%	0.41	43.5%	6.8%	TransAlta Corp	9.7%	0.39	7.6%	0.10	6.0%	0.51	43.5%	6.3%	
IPL Energy Inc.	9.3%	0.45	5.9%	0.01	6.1%	0.54	43.5%	6.1%	IPL Energy Inc.	9.4%	0.26	5.9%	0.02	6.1%	0.72	43.5%	5.1%	
Pacific Northern	9.4%	0.43	6.5%	0.05	6.2%	0.53	43.5%	6.2%	Pacific Northern	9.5%	0.34	6.5%	0.06	6.2%	0.59	43.5%	5.8%	
Westcoast Energy	9.3%	0.30	5.8%	0.07	6.1%	0.63	43.5%	5.4%	Westcoast Energy	9.5%	0.25	5.8%	0.08	6.1%	0.67	43.5%	5.1%	
Elect Co. average	9.5%	0.44	6.1%	0.10	6.1%	0.46	43.5%	6.4%	Elect Co. average	9.7%	0.36	6.1%	0.12	6.1%	0.52	43.5%	6.0%	36
Average	9.4%	0.43	5.5%	0.07	6.1%	0.50	43.5%	6.2%	Average	9.6%	0.34	5.5%	0.08	6.1%	0.58	43.5%	5.7%	47

Panel F

MARKET	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	BOOK	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	Market Minus Book Difference
BC Gas Inc.	8.6%	0.34	6.4%	0.06	6.1%	0.60	43.5%	5.4%	BC Gas Inc.	8.6%	0.29	6.4%	0.07	6.1%	0.64	43.5%	5.1%	
Canadian Utilities	9.4%	0.43	5.6%	0.15	6.0%	0.42	43.5%	6.3%	Canadian Utilities	9.4%	0.33	5.6%	0.18	6.0%	0.48	43.5%	5.8%	
Fortis Inc.	7.7%	0.44	5.5%	0.10	6.1%	0.46	43.5%	5.5%	Fortis Inc.	7.7%	0.40	5.5%	0.12	6.1%	0.49	43.5%	5.4%	
Gaz Met	7.8%	0.62	0.0%	0.00	6.1%	0.37	43.5%	6.1%	Gaz Met	7.8%	0.46	0.0%	0.00	6.1%	0.54	43.5%	5.4%	
Nova Scotia Power	8.1%	0.38	5.8%	0.07	6.1%	0.55	43.5%	5.4%	Nova Scotia Power	8.1%	0.32	5.8%	0.08	6.1%	0.60	43.5%	5.1%	
TransAlta Corp	8.4%	0.51	7.6%	0.08	6.0%	0.41	43.5%	6.3%	TransAlta Corp	8.4%	0.39	7.6%	0.10	6.0%	0.51	43.5%	5.8%	
IPL Energy Inc.	8.1%	0.45	5.9%	0.01	6.1%	0.54	43.5%	5.6%	IPL Energy Inc.	8.1%	0.26	5.9%	0.02	6.1%	0.72	43.5%	4.7%	
Pacific Northern	8.2%	0.43	6.5%	0.05	6.2%	0.53	43.5%	5.7%	Pacific Northern	8.2%	0.34	6.5%	0.06	6.2%	0.59	43.5%	5.3%	
Westcoast Energy	8.2%	0.30	5.8%	0.07	6.1%	0.63	43.5%	5.0%	Westcoast Energy	8.2%	0.25	5.8%	0.08	6.1%	0.67	43.5%	4.8%	
Elect Co. average	8.4%	0.44	6.1%	0.10	6.1%	0.46	43.5%	5.9%	Elect Co. average	8.4%	0.36	6.1%	0.12	6.1%	0.52	43.5%	5.5%	36
Average	8.3%	0.43	5.5%	0.07	6.1%	0.50	43.5%	5.7%	Average	8.3%	0.34	5.5%	0.08	6.1%	0.58	43.5%	5.3%	42

Canadian Sample Companies (continued)

Panel G

MARKET	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	BOOK	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	Market Minus Book Difference
BC Gas Inc.	10.0%	0.34	6.4%	0.06	6.1%	0.60	43.5%	5.9%	BC Gas Inc.	10.0%	0.29	6.4%	0.07	6.1%	0.64	43.5%	5.6%	
Canadian Utilities	10.4%	0.43	5.6%	0.15	6.0%	0.42	43.5%	6.7%	Canadian Utilities	10.4%	0.33	5.6%	0.18	6.0%	0.48	43.5%	6.1%	
Fortis Inc.	9.5%	0.44	5.5%	0.10	6.1%	0.46	43.5%	6.3%	Fortis Inc.	9.5%	0.40	5.5%	0.12	6.1%	0.49	43.5%	6.1%	
Gaz Met	9.6%	0.62	0.0%	0.00	6.1%	0.37	43.5%	7.2%	Gaz Met	9.6%	0.46	0.0%	0.00	6.1%	0.54	43.5%	6.3%	
Nova Scotia Power	9.7%	0.38	5.8%	0.07	6.1%	0.55	43.5%	6.0%	Nova Scotia Power	9.7%	0.32	5.8%	0.08	6.1%	0.60	43.5%	5.6%	
TransAlta Corp	9.9%	0.51	7.6%	0.08	6.0%	0.41	43.5%	7.0%	TransAlta Corp	9.9%	0.39	7.6%	0.10	6.0%	0.51	43.5%	6.4%	
IPL Energy Inc.	9.7%	0.45	5.9%	0.01	6.1%	0.54	43.5%	6.3%	IPL Energy Inc.	9.7%	0.26	5.9%	0.02	6.1%	0.72	43.5%	5.1%	
Pacific Northern	9.8%	0.43	6.5%	0.05	6.2%	0.53	43.5%	6.4%	Pacific Northern	9.8%	0.34	6.5%	0.06	6.2%	0.59	43.5%	5.9%	
Westcoast Energy	9.7%	0.30	5.8%	0.07	6.1%	0.63	43.5%	5.5%	Westcoast Energy	9.7%	0.25	5.8%	0.08	6.1%	0.67	43.5%	5.2%	
Elect Co. average	9.9%	0.44	6.1%	0.10	6.1%	0.46	43.5%	6.5%	Elect Co. average	9.9%	0.36	6.1%	0.12	6.1%	0.52	43.5%	6.1%	47
Average	9.8%	0.43	5.5%	0.07	6.1%	0.50	43.5%	6.4%	Average	9.8%	0.34	5.5%	0.08	6.1%	0.58	43.5%	5.8%	57

Panel H

MARKET	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	BOOK	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	Market Minus Book Difference
BC Gas Inc.	10.3%	0.34	6.4%	0.06	6.1%	0.60	43.5%	6.0%	BC Gas Inc.	10.3%	0.29	6.4%	0.07	6.1%	0.64	43.5%	5.6%	
Canadian Utilities	10.7%	0.43	5.6%	0.15	6.0%	0.42	43.5%	6.9%	Canadian Utilities	10.7%	0.33	5.6%	0.18	6.0%	0.48	43.5%	6.2%	
Fortis Inc.	9.9%	0.44	5.5%	0.10	6.1%	0.46	43.5%	6.5%	Fortis Inc.	9.9%	0.40	5.5%	0.12	6.1%	0.49	43.5%	6.3%	
Gaz Met	10.0%	0.62	0.0%	0.00	6.1%	0.37	43.5%	7.5%	Gaz Met	10.0%	0.46	0.0%	0.00	6.1%	0.54	43.5%	6.4%	
Nova Scotia Power	10.1%	0.38	5.8%	0.07	6.1%	0.55	43.5%	6.1%	Nova Scotia Power	10.1%	0.32	5.8%	0.08	6.1%	0.60	43.5%	5.8%	
TransAlta Corp	10.2%	0.51	7.6%	0.08	6.0%	0.41	43.5%	7.2%	TransAlta Corp	10.2%	0.39	7.6%	0.10	6.0%	0.51	43.5%	6.5%	
IPL Energy Inc.	10.1%	0.45	5.9%	0.01	6.1%	0.54	43.5%	6.5%	IPL Energy Inc.	10.1%	0.26	5.9%	0.02	6.1%	0.72	43.5%	5.2%	
Pacific Northern	10.1%	0.43	6.5%	0.05	6.2%	0.53	43.5%	6.5%	Pacific Northern	10.1%	0.34	6.5%	0.06	6.2%	0.59	43.5%	6.0%	
Westcoast Energy	10.1%	0.30	5.8%	0.07	6.1%	0.63	43.5%	5.6%	Westcoast Energy	10.1%	0.25	5.8%	0.08	6.1%	0.67	43.5%	5.3%	
Elect Co. average	10.2%	0.44	6.1%	0.10	6.1%	0.46	43.5%	6.7%	Elect Co. average	10.2%	0.36	6.1%	0.12	6.1%	0.52	43.5%	6.2%	49
Average	10.2%	0.43	5.5%	0.07	6.1%	0.50	43.5%	6.5%	Average	10.2%	0.34	5.5%	0.08	6.1%	0.58	43.5%	5.9%	60

Canadian Sample Companies (continued)

Panel I

MARKET	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	BOOK	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	Market Minus Book Difference
BC Gas Inc.	9.1%	0.34	6.4%	0.06	6.1%	0.60	43.5%	5.5%	BC Gas Inc.	9.1%	0.29	6.4%	0.07	6.1%	0.64	43.5%	5.3%	
Canadian Utilities	9.8%	0.43	5.6%	0.15	6.0%	0.42	43.5%	6.5%	Canadian Utilities	9.8%	0.33	5.6%	0.18	6.0%	0.48	43.5%	5.9%	
Fortis Inc.	8.4%	0.44	5.5%	0.10	6.1%	0.46	43.5%	5.8%	Fortis Inc.	8.4%	0.40	5.5%	0.12	6.1%	0.49	43.5%	5.7%	
Gaz Met	8.5%	0.62	0.0%	0.00	6.1%	0.37	43.5%	6.5%	Gaz Met	8.5%	0.46	0.0%	0.00	6.1%	0.54	43.5%	5.8%	
Nova Scotia Power	8.7%	0.38	5.8%	0.07	6.1%	0.55	43.5%	5.6%	Nova Scotia Power	8.7%	0.32	5.8%	0.08	6.1%	0.60	43.5%	5.3%	
TransAlta Corp	8.9%	0.51	7.6%	0.08	6.0%	0.41	43.5%	6.5%	TransAlta Corp	8.9%	0.39	7.6%	0.10	6.0%	0.51	43.5%	6.0%	
IPL Energy Inc.	8.7%	0.45	5.9%	0.01	6.1%	0.54	43.5%	5.8%	IPL Energy Inc.	8.7%	0.26	5.9%	0.02	6.1%	0.72	43.5%	4.9%	
Pacific Northern	8.8%	0.43	6.5%	0.05	6.2%	0.53	43.5%	6.0%	Pacific Northern	8.8%	0.34	6.5%	0.06	6.2%	0.59	43.5%	5.5%	
Westcoast Energy	8.8%	0.30	5.8%	0.07	6.1%	0.63	43.5%	5.2%	Westcoast Energy	8.8%	0.25	5.8%	0.08	6.1%	0.67	43.5%	5.0%	
Elect Co. average	9.0%	0.44	6.1%	0.10	6.1%	0.46	43.5%	6.1%	Elect Co. average	9.0%	0.36	6.1%	0.12	6.1%	0.52	43.5%	5.7%	40
Average	8.9%	0.43	5.5%	0.07	6.1%	0.50	43.5%	6.0%	Average	8.9%	0.34	5.5%	0.08	6.1%	0.58	43.5%	5.5%	48

Panel J

MARKET	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	BOOK	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	Market Minus Book Difference
BC Gas Inc.	9.6%	0.34	6.4%	0.06	6.1%	0.60	43.5%	5.7%	BC Gas Inc.	9.6%	0.29	6.4%	0.07	6.1%	0.64	43.5%	5.4%	
Canadian Utilities	10.2%	0.43	5.6%	0.15	6.0%	0.42	43.5%	6.6%	Canadian Utilities	10.2%	0.33	5.6%	0.18	6.0%	0.48	43.5%	6.1%	
Fortis Inc.	9.0%	0.44	5.5%	0.10	6.1%	0.46	43.5%	6.1%	Fortis Inc.	9.0%	0.40	5.5%	0.12	6.1%	0.49	43.5%	5.9%	
Gaz Met	9.1%	0.62	0.0%	0.00	6.1%	0.37	43.5%	6.9%	Gaz Met	9.1%	0.46	0.0%	0.00	6.1%	0.54	43.5%	6.0%	
Nova Scotia Power	9.3%	0.38	5.8%	0.07	6.1%	0.55	43.5%	5.8%	Nova Scotia Power	9.3%	0.32	5.8%	0.08	6.1%	0.60	43.5%	5.5%	
TransAlta Corp	9.5%	0.51	7.6%	0.08	6.0%	0.41	43.5%	6.8%	TransAlta Corp	9.5%	0.39	7.6%	0.10	6.0%	0.51	43.5%	6.2%	
IPL Energy Inc.	9.3%	0.45	5.9%	0.01	6.1%	0.54	43.5%	6.1%	IPL Energy Inc.	9.3%	0.26	5.9%	0.02	6.1%	0.72	43.5%	5.0%	
Pacific Northern	9.4%	0.43	6.5%	0.05	6.2%	0.53	43.5%	6.2%	Pacific Northern	9.4%	0.34	6.5%	0.06	6.2%	0.59	43.5%	5.7%	
Westcoast Energy	9.3%	0.30	5.8%	0.07	6.1%	0.63	43.5%	5.4%	Westcoast Energy	9.3%	0.25	5.8%	0.08	6.1%	0.67	43.5%	5.1%	
Elect Co. average	9.5%	0.44	6.1%	0.10	6.1%	0.46	43.5%	6.4%	Elect Co. average	9.5%	0.36	6.1%	0.12	6.1%	0.52	43.5%	5.9%	44
Average	9.4%	0.43	5.5%	0.07	6.1%	0.50	43.5%	6.2%	Average	9.4%	0.34	5.5%	0.08	6.1%	0.58	43.5%	5.7%	53
Wgt Elect Ave	9.9%	0.44	6.1%	0.10	6.1%	0.46	43.5%	6.5%	Wgt Elect Ave	9.9%	0.36	6.1%	0.12	6.1%	0.52	43.5%	6.1%	46
Overall Can Ave	9.4%	0.43	5.5%	0.07	6.1%	0.50	43.5%	6.1%	Overall Can Ave	9.4%	0.34	5.5%	0.08	6.1%	0.58	43.5%	5.6%	53

US Sample Companies / Source: Evidence of Dr. Vilbert MJV-13, Panels A-I

			($000)					
Boston Edison		Book Ratios	Ave	1997	1996	1995	1994	1993
Book Equity		0.41	978	1,073	1,036	989	916	876
Preferred		0.08	203	161	201	215	217	219
Debt	Short		126	85	127	105	186	128
	Long		1,217	1,158	1,159	1,261	1,237	1,272
	Total	0.51	1,344					
		1.00	2,619					
Consolidated Edison		Book Ratios	Ave	1,997	1996	1995	1994	1993
Book Equity		0.54	5,513	5,930	5,728	5,523	5,313	5,069
Preferred		0.05	512	318	323	640	640	641
Debt	Short		0	0	0	0	0	0
	Long		4,242	4,758	4,388	4,146	4,089	3,828
	Total	0.41	4,242					
		1.00	10,267					
DTE Energy		Book Ratios	Ave	1997	1996	1995	1994	1993
Book Equity		0.43	3,405	3,556	3,438	3,428	3,316	3,286
Preferred		0.04	283	150	150	335	391	391
Debt	Short		33	0	0	0	28	138
	Long		4,186	4,229	4,184	4,158	4,172	4,189
	Total	0.53	4,220					
		1.00	7,908					
Eastern Utilities		Book Ratios	Ave	1997	1996	1995	1994	1993
Book Equity		0.48	364	373	372	375	365	333
Preferred		0.04	33	35	34	33	32	32
Debt	Short		0	0	0	0	0	0
	Long		358	405	434	454	497	502
	Total	0.47	358					
		1.00	755					
GPU Inc.		Book Ratios	Ave	1997	1996	1995	1994	1993
Book Equity		0.43	2,861	3,100	3,048	2,975	2,573	2,611
Preferred		0.02	163	157	180	231	247	307
Debt	Short		122	134	127	0	239	112
	Long		3,578	5,418	3,826	3,190	2,816	2,639
	Total	0.55	3700					
		1.00	6,725					

US Sample Companies (continued)

			($000)					
New England Electric		Book Ratios	Ave	1997	1996	1995	1994	1993
Book Equity		0.48	1,634	1,744	1,685	1,632	1,581	1,530
Preferred		0.04	121	39	126	147	147	148
Debt	Short		32	111	0	7	44	0
	Long		1,652	1,577	1,694	1,752	1,649	1,589
	Total	0.49	1,685					
		1.0	3,440					
OGE Energy.		Book Ratios	Ave	1997	1996	1995	1994	1993
Book Equity		0.51	943	985	962	938	921	907
Preferred		0.03	50	49	49	50	50	50
Debt	Short		27	0	0	0	92	42
	Long		830	867	844	844	756	839
	Total	0.46	857					
		1.00	1,849					
Pinnacle West		Book Ratios	Ave	1997	1996	1995	1994	1993
Book Equity		0.40	1,861	2,027	1,970	1,881	1,776	1,650
Preferred		0.06	264	171	219	269	269	391
Debt	Short		17	0	0	65	18	0
	Long		2,556	2,353	2,528	2,519	2,667	2,712
	Total	0.55	2,572					
		1.00	4,697					
PP&L Resources		Book Ratios	Ave	1997	1996	1995	1994	1993
		0.43	2,606	2,809	2,745	2,597	2,454	2,426
Book Equity		0.07	400	97	466	466	466	506
Preferred			7	0	0	0	0	33
Debt	Short		3,078	3,156	3,079	3,078	3,166	2,912
	Long	0.51	3,085					
	Total	1.00	6,091					

US Sample Companies (continued) / Source: Evidence of Dr. Vilbert MJV-19, Panels A-J

Panel A

MARKET	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	BOOK	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	Market Minus Book Difference
Boston Edison	10.6%	0.48	6.6%	0.07	6.1%	0.45	43.5%	7.1%	Boston Edison	10.6%	0.41	6.6%	0.08	6.1%	0.51	43.5%	6.6%	
Consolidated Edison	11.1%	0.61	6.2%	0.04	6.1%	0.35	43.5%	8.2%	Consolidated Edison	11.1%	0.54	6.2%	0.05	6.1%	0.41	43.5%	7.7%	
DTE Energy	10.4%	0.51	6.6%	0.03	6.2%	0.46	43.5%	7.1%	DTE Energy	10.4%	0.43	6.6%	0.04	6.2%	0.53	43.5%	6.6%	
Eastern Utilities	11.1%	0.49	6.6%	0.04	6.2%	0.48	43.5%	7.4%	Eastern Utilities	11.1%	0.48	6.6%	0.04	6.2%	0.47	43.5%	7.3%	
GPU Inc.	11.0%	0.50	6.6%	0.03	6.2%	0.47	43.5%	7.3%	GPU Inc.	11.0%	0.43	6.6%	0.02	6.2%	0.55	43.5%	6.8%	
New England Elect.	9.7%	0.58	6.2%	0.03	6.1%	0.40	43.5%	7.2%	New England Elect.	9.7%	0.48	6.2%	0.04	6.1%	0.49	43.5%	6.5%	
OGE Energy	9.7%	0.65	6.2%	0.02	6.0%	0.33	43.5%	7.5%	OGE Energy	9.7%	0.51	6.2%	0.03	6.0%	0.46	43.5%	6.7%	
Pinnacle West	9.8%	0.47	6.6%	0.05	6.2%	0.48	43.5%	6.6%	Pinnacle West	9.8%	0.40	6.6%	0.06	6.2%	0.55	43.5%	6.2%	
PP&L Resources	9.6%	0.52	6.6%	0.05	6.1%	0.43	43.5%	6.8%	PP&L Resources	9.6%	0.43	6.6%	0.07	6.1%	0.51	43.5%	6.3%	
Average	10.3%	0.53	6.5%	0.04	6.1%	0.43	43.5%	7.3%	Average	10.3%	0.45	6.5%	0.05	6.1%	0.50	43.5%	6.7%	52

Panel B

MARKET	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	BOOK	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	Market Minus Book Difference
Boston Edison	9.7%	0.48	6.6%	0.07	6.1%	0.45	43.5%	6.7%	Boston Edison	9.7%	0.41	6.6%	0.08	6.1%	0.51	43.5%	6.3%	
Consolidated Edison	10.5%	0.61	6.2%	0.04	6.1%	0.35	43.5%	7.9%	Consolidated Edison	10.5%	0.54	6.2%	0.05	6.1%	0.41	43.5%	7.4%	
DTE Energy	9.5%	0.51	6.6%	0.03	6.2%	0.46	43.5%	6.7%	DTE Energy	9.5%	0.43	6.6%	0.04	6.2%	0.53	43.5%	6.2%	
Eastern Utilities	10.5%	0.49	6.6%	0.04	6.2%	0.48	43.5%	7.1%	Eastern Utilities	10.5%	0.48	6.6%	0.04	6.2%	0.47	43.5%	7.0%	
GPU Inc.	10.3%	0.50	6.6%	0.03	6.2%	0.47	43.5%	7.0%	GPU Inc.	10.3%	0.43	6.6%	0.02	6.2%	0.55	43.5%	6.5%	
New England Elect.	8.4%	0.58	6.2%	0.03	6.1%	0.40	43.5%	6.4%	New England Elect.	8.4%	0.48	6.2%	0.04	6.1%	0.49	43.5%	5.9%	
OGE Energy	8.4%	0.65	6.2%	0.02	6.0%	0.33	43.5%	6.7%	OGE Energy	8.4%	0.51	6.2%	0.03	6.0%	0.46	43.5%	6.0%	
Pinnacle West	8.6%	0.47	6.6%	0.05	6.2%	0.48	43.5%	6.1%	Pinnacle West	8.6%	0.40	6.6%	0.06	6.2%	0.55	43.5%	5.7%	
PP&L Resources	8.3%	0.52	6.6%	0.05	6.1%	0.43	43.5%	6.1%	PP&L Resources	8.3%	0.43	6.6%	0.07	6.1%	0.51	43.5%	5.7%	
Average	9.4%	0.53	6.5%	0.04	6.1%	0.43	43.5%	6.7%	Average	9.4%	0.45	6.5%	0.05	6.1%	0.50	43.5%	6.3%	44

US Sample Companies (continued)

Panel C

MARKET	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	BOOK	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	Market Minus Book Difference
Boston Edison	11.1%	0.48	6.6%	0.07	6.1%	0.45	43.5%	7.3%	Boston Edison	11.1%	0.41	6.6%	0.08	6.1%	0.51	43.5%	6.8%	
Consolidated Edison	11.4%	0.61	6.2%	0.04	6.1%	0.35	43.5%	8.4%	Consolidated Edison	11.4%	0.54	6.2%	0.05	6.1%	0.41	43.5%	7.9%	
DTE Energy	10.9%	0.51	6.6%	0.03	6.2%	0.46	43.5%	7.4%	DTE Energy	10.9%	0.43	6.6%	0.04	6.2%	0.53	43.5%	6.8%	
Eastern Utilities	11.4%	0.49	6.6%	0.04	6.2%	0.48	43.5%	7.5%	Eastern Utilities	11.4%	0.48	6.6%	0.04	6.2%	0.47	43.5%	7.4%	
GPU Inc.	11.3%	0.50	6.6%	0.03	6.2%	0.47	43.5%	7.5%	GPU Inc.	11.3%	0.43	6.6%	0.02	6.2%	0.55	43.5%	6.9%	
New England Elect.	10.4%	0.58	6.2%	0.03	6.1%	0.40	43.5%	7.6%	New England Elect.	10.4%	0.48	6.2%	0.04	6.1%	0.49	43.5%	6.8%	
OGE Energy	10.4%	0.65	6.2%	0.02	6.0%	0.33	43.5%	8.0%	OGE Energy	10.4%	0.51	6.2%	0.03	6.0%	0.46	43.5%	7.0%	
Pinnacle West	10.5%	0.47	6.6%	0.05	6.2%	0.48	43.5%	6.9%	Pinnacle West	10.5%	0.40	6.6%	0.06	6.2%	0.55	43.5%	6.4%	
PP&L Resources	10.4%	0.52	6.6%	0.05	6.1%	0.43	43.5%	7.2%	PP&L Resources	10.4%	0.43	6.6%	0.07	6.1%	0.51	43.5%	6.6%	
Average	10.9%	0.53	6.5%	0.04	6.1%	0.43	43.5%	7.5%	Average	10.9%	0.45	6.5%	0.05	6.1%	0.50	43.5%	7.0%	57

Panel D

MARKET	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	BOOK	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	Market Minus Book Difference
Boston Edison	10.5%	0.48	6.6%	0.07	6.1%	0.45	43.5%	7.1%	Boston Edison	10.5%	0.41	6.6%	0.08	6.1%	0.51	43.5%	6.6%	
Consolidated Edison	11.0%	0.61	6.2%	0.04	6.1%	0.35	43.5%	8.2%	Consolidated Edison	11.0%	0.54	6.2%	0.05	6.1%	0.41	43.5%	7.6%	
DTE Energy	10.3%	0.51	6.6%	0.03	6.2%	0.46	43.5%	7.1%	DTE Energy	10.3%	0.43	6.6%	0.04	6.2%	0.53	43.5%	6.5%	
Eastern Utilities	11.0%	0.49	6.6%	0.04	6.2%	0.48	43.5%	7.3%	Eastern Utilities	11.0%	0.48	6.6%	0.04	6.2%	0.47	43.5%	7.3%	
GPU Inc.	10.9%	0.50	6.6%	0.03	6.2%	0.47	43.5%	7.3%	GPU Inc.	10.9%	0.43	6.6%	0.02	6.2%	0.55	43.5%	6.7%	
New England Elect.	9.5%	0.58	6.2%	0.03	6.1%	0.40	43.5%	7.1%	New England Elect.	9.5%	0.48	6.2%	0.04	6.1%	0.49	43.5%	6.4%	
OGE Energy	9.5%	0.65	6.2%	0.02	6.0%	0.33	43.5%	7.4%	OGE Energy	9.5%	0.51	6.2%	0.03	6.0%	0.46	43.5%	6.6%	
Pinnacle West	9.6%	0.47	6.6%	0.05	6.2%	0.48	43.5%	6.5%	Pinnacle West	9.6%	0.40	6.6%	0.06	6.2%	0.55	43.5%	6.1%	
PP&L Resources	9.5%	0.52	6.6%	0.05	6.1%	0.43	43.5%	6.8%	PP&L Resources	9.5%	0.43	6.6%	0.07	6.1%	0.51	43.5%	6.2%	
Average	10.2%	0.53	6.5%	0.04	6.1%	0.43	43.5%	7.2%	Average	10.2%	0.45	6.5%	0.05	6.1%	0.50	43.5%	6.7%	51

US Sample Companies (continued)

Panel E

MARKET	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	BOOK	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	Market Minus Book Difference
Boston Edison	10.3%	0.48	6.6%	0.07	6.1%	0.45	43.5%	7.0%	Boston Edison	10.3%	0.41	6.6%	0.08	6.1%	0.51	43.5%	6.5%	
Consolidated Edison	10.7%	0.61	6.2%	0.04	6.1%	0.35	43.5%	8.0%	Consolidated Edison	10.7%	0.54	6.2%	0.05	6.1%	0.41	43.5%	7.5%	
DTE Energy	10.1%	0.51	6.6%	0.03	6.2%	0.46	43.5%	7.0%	DTE Energy	10.1%	0.43	6.6%	0.04	6.2%	0.53	43.5%	6.5%	
Eastern Utilities	10.7%	0.49	6.6%	0.04	6.2%	0.48	43.5%	7.2%	Eastern Utilities	10.7%	0.48	6.6%	0.04	6.2%	0.47	43.5%	7.1%	
GPU Inc.	10.6%	0.50	6.6%	0.03	6.2%	0.47	43.5%	7.1%	GPU Inc.	10.6%	0.43	6.6%	0.02	6.2%	0.55	43.5%	6.6%	
New England Elect.	9.5%	0.58	6.2%	0.03	6.1%	0.40	43.5%	7.1%	New England Elect.	9.5%	0.48	6.2%	0.04	6.1%	0.49	43.5%	6.4%	
OGE Energy	9.5%	0.65	6.2%	0.02	6.0%	0.33	43.5%	7.4%	OGE Energy	9.5%	0.51	6.2%	0.03	6.0%	0.46	43.5%	6.6%	
Pinnacle West	9.6%	0.47	6.6%	0.05	6.2%	0.48	43.5%	6.5%	Pinnacle West	9.6%	0.40	6.6%	0.06	6.2%	0.55	43.5%	6.1%	
PP&L Resources	9.5%	0.52	6.6%	0.05	6.1%	0.43	43.5%	6.8%	PP&L Resources	9.5%	0.43	6.6%	0.07	6.1%	0.51	43.5%	6.2%	
Average	10.1%	0.53	6.5%	0.04	6.1%	0.43	43.5%	7.1%	Average	10.1%	0.45	6.5%	0.05	6.1%	0.50	43.5%	6.6%	50

Panel F

MARKET	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	BOOK	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	Market Minus Book Difference
Boston Edison	9.5%	0.48	6.6%	0.07	6.1%	0.45	43.5%	6.6%	Boston Edison	9.5%	0.41	6.6%	0.08	6.1%	0.51	43.5%	6.2%	
Consolidated Edison	10.2%	0.61	6.2%	0.04	6.1%	0.35	43.5%	7.7%	Consolidated Edison	10.2%	0.54	6.2%	0.05	6.1%	0.41	43.5%	7.2%	
DTE Energy	9.3%	0.51	6.6%	0.03	6.2%	0.46	43.5%	6.6%	DTE Energy	9.3%	0.43	6.6%	0.04	6.2%	0.53	43.5%	6.1%	
Eastern Utilities	10.2%	0.49	6.6%	0.04	6.2%	0.48	43.5%	6.9%	Eastern Utilities	10.2%	0.48	6.6%	0.04	6.2%	0.47	43.5%	6.9%	
GPU Inc.	10.0%	0.50	6.6%	0.03	6.2%	0.47	43.5%	6.8%	GPU Inc.	10.0%	0.43	6.6%	0.02	6.2%	0.55	43.5%	6.3%	
New England Elect.	8.4%	0.58	6.2%	0.03	6.1%	0.40	43.5%	6.4%	New England Elect.	8.4%	0.48	6.2%	0.04	6.1%	0.49	43.5%	5.9%	
OGE Energy	8.4%	0.65	6.2%	0.02	6.0%	0.33	43.5%	6.7%	OGE Energy	8.4%	0.51	6.2%	0.03	6.0%	0.46	43.5%	6.0%	
Pinnacle West	8.6%	0.47	6.6%	0.05	6.2%	0.48	43.5%	6.1%	Pinnacle West	8.6%	0.40	6.6%	0.06	6.2%	0.55	43.5%	5.7%	
PP&L Resources	8.4%	0.52	6.6%	0.05	6.1%	0.43	43.5%	6.2%	PP&L Resources	8.4%	0.43	6.6%	0.07	6.1%	0.51	43.5%	5.8%	
Average	9.2%	0.53	6.5%	0.04	6.1%	0.43	43.5%	6.7%	Average	9.2%	0.45	6.5%	0.05	6.1%	0.50	43.5%	6.2%	43

US Sample Companies (continued)

Panel G

MARKET	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	BOOK	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	Market Minus Book Difference
Boston Edison	10.5%	0.48	6.6%	0.07	6.1%	0.45	43.5%	7.1%	Boston Edison	10.5%	0.41	6.6%	0.08	6.1%	0.51	43.5%	6.6%	
Consolidated Edison	10.9%	0.61	6.2%	0.04	6.1%	0.35	43.5%	8.1%	Consolidated Edison	10.9%	0.54	6.2%	0.05	6.1%	0.41	43.5%	7.6%	
DTE Energy	10.4%	0.51	6.6%	0.03	6.2%	0.46	43.5%	7.1%	DTE Energy	10.4%	0.43	6.6%	0.04	6.2%	0.53	43.5%	6.6%	
Eastern Utilities	10.9%	0.49	6.6%	0.04	6.2%	0.48	43.5%	7.3%	Eastern Utilities	10.9%	0.48	6.6%	0.04	6.2%	0.47	43.5%	7.2%	
GPU Inc.	10.8%	0.50	6.6%	0.03	6.2%	0.47	43.5%	7.2%	GPU Inc.	10.8%	0.43	6.6%	0.02	6.2%	0.55	43.5%	6.7%	
New England Elect.	9.9%	0.58	6.2%	0.03	6.1%	0.40	43.5%	7.3%	New England Elect.	9.9%	0.48	6.2%	0.04	6.1%	0.49	43.5%	6.6%	
OGE Energy	9.9%	0.65	6.2%	0.02	6.0%	0.33	43.5%	7.7%	OGE Energy	9.9%	0.51	6.2%	0.03	6.0%	0.46	43.5%	6.8%	
Pinnacle West	10.0%	0.47	6.6%	0.05	6.2%	0.48	43.5%	6.7%	Pinnacle West	10.0%	0.40	6.6%	0.06	6.2%	0.55	43.5%	6.3%	
PP&L Resources	9.8%	0.52	6.6%	0.05	6.1%	0.43	43.5%	6.9%	PP&L Resources	9.8%	0.43	6.6%	0.07	6.1%	0.51	43.5%	6.4%	
Average	10.3%	0.53	6.5%	0.04	6.1%	0.43	43.5%	7.3%	Average	10.3%	0.45	6.5%	0.05	6.1%	0.50	43.5%	6.7%	53

Panel H

MARKET	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	BOOK	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	Market Minus Book Difference
Boston Edison	10.7%	0.48	6.6%	0.07	6.1%	0.45	43.5%	7.1%	Boston Edison	10.7%	0.41	6.6%	0.08	6.1%	0.51	43.5%	6.7%	
Consolidated Edison	11.0%	0.61	6.2%	0.04	6.1%	0.35	43.5%	8.2%	Consolidated Edison	11.0%	0.54	6.2%	0.05	6.1%	0.41	43.5%	7.6%	
DTE Energy	10.7%	0.51	6.6%	0.03	6.2%	0.46	43.5%	7.3%	DTE Energy	10.7%	0.43	6.6%	0.04	6.2%	0.53	43.5%	6.7%	
Eastern Utilities	11.0%	0.49	6.6%	0.04	6.2%	0.48	43.5%	7.3%	Eastern Utilities	11.0%	0.48	6.6%	0.04	6.2%	0.47	43.5%	7.3%	
GPU Inc.	11.0%	0.50	6.6%	0.03	6.2%	0.47	43.5%	7.3%	GPU Inc.	11.0%	0.43	6.6%	0.02	6.2%	0.55	43.5%	6.8%	
New England Elect.	10.2%	0.58	6.2%	0.03	6.1%	0.40	43.5%	7.5%	New England Elect.	10.2%	0.48	6.2%	0.04	6.1%	0.49	43.5%	6.8%	
OGE Energy	10.2%	0.65	6.2%	0.02	6.0%	0.33	43.5%	7.9%	OGE Energy	10.2%	0.51	6.2%	0.03	6.0%	0.46	43.5%	6.9%	
Pinnacle West	10.3%	0.47	6.6%	0.05	6.2%	0.48	43.5%	6.9%	Pinnacle West	10.3%	0.40	6.6%	0.06	6.2%	0.55	43.5%	6.4%	
PP&L Resources	10.2%	0.52	6.6%	0.05	6.1%	0.43	43.5%	7.1%	PP&L Resources	10.2%	0.43	6.6%	0.07	6.1%	0.51	43.5%	6.5%	
Average	10.6%	0.53	6.5%	0.04	6.1%	0.43	43.5%	7.4%	Average	10.6%	0.45	6.5%	0.05	6.1%	0.50	43.5%	6.8%	55

US Sample Companies (continued)

Panel I

MARKET	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC
Boston Edison	9.9%	0.48	6.6%	0.07	6.1%	0.45	43.5%	6.8%
Consolidated Edison	10.5%	0.61	6.2%	0.04	6.1%	0.35	43.5%	7.9%
DTE Energy	9.7%	0.51	6.6%	0.03	6.2%	0.46	43.5%	6.8%
Eastern Utilities	10.5%	0.49	6.6%	0.04	6.2%	0.48	43.5%	7.1%
GPU Inc.	10.3%	0.50	6.6%	0.03	6.2%	0.47	43.5%	7.0%
New England Elect.	9.0%	0.58	6.2%	0.03	6.1%	0.40	43.5%	6.8%
OGE Energy	9.0%	0.65	6.2%	0.02	6.0%	0.33	43.5%	7.1%
Pinnacle West	9.1%	0.47	6.6%	0.05	6.2%	0.48	43.5%	6.3%
PP&L Resources	8.9%	0.52	6.6%	0.05	6.1%	0.43	43.5%	6.4%
Average	9.7%	0.53	6.5%	0.04	6.1%	0.43	43.5%	6.9%

BOOK	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	Market Minus Book Difference
Boston Edison	9.9%	0.41	6.6%	0.08	6.1%	0.51	43.5%	6.3%	
Consolidated Edison	10.5%	0.54	6.2%	0.05	6.1%	0.41	43.5%	7.4%	
DTE Energy	9.7%	0.43	6.6%	0.04	6.2%	0.53	43.5%	6.3%	
Eastern Utilities	10.5%	0.48	6.6%	0.04	6.2%	0.47	43.5%	7.0%	
GPU Inc.	10.3%	0.43	6.6%	0.02	6.2%	0.55	43.5%	6.5%	
New England Elect.	9.0%	0.48	6.2%	0.04	6.1%	0.49	43.5%	6.2%	
OGE Energy	9.0%	0.51	6.2%	0.03	6.0%	0.46	43.5%	6.3%	
Pinnacle West	9.1%	0.40	6.6%	0.06	6.2%	0.55	43.5%	5.9%	
PP&L Resources	8.9%	0.43	6.6%	0.07	6.1%	0.51	43.5%	6.0%	
Average	9.7%	0.45	6.5%	0.05	6.1%	0.50	43.5%	6.4%	47

Panel J

MARKET	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC
Boston Edison	10.3%	0.48	6.6%	0.07	6.1%	0.45	43.5%	7.0%
Consolidated Edison	10.7%	0.61	6.2%	0.04	6.1%	0.35	43.5%	8.0%
DTE Energy	10.1%	0.51	6.6%	0.03	6.2%	0.46	43.5%	7.0%
Eastern Utilities	10.7%	0.49	6.6%	0.04	6.2%	0.48	43.5%	7.2%
GPU Inc.	10.6%	0.50	6.6%	0.03	6.2%	0.47	43.5%	7.1%
New England Elect.	9.5%	0.58	6.2%	0.03	6.1%	0.40	43.5%	7.1%
OGE Energy	9.5%	0.65	6.2%	0.02	6.0%	0.33	43.5%	7.4%
Pinnacle West	9.6%	0.47	6.6%	0.05	6.2%	0.48	43.5%	6.5%
PP&L Resources	9.5%	0.52	6.6%	0.05	6.1%	0.43	43.5%	6.8%
Average	10.1%	0.53	6.5%	0.04	6.1%	0.43	43.5%	7.1%

BOOK	Equity %	E/V	Pref %	P/V	Debt %	D/V	I.T.	ATWACC	Market Minus Book Difference
Boston Edison	10.3%	0.41	6.6%	0.08	6.1%	0.51	43.5%	6.5%	
Consolidated Edison	10.7%	0.54	6.2%	0.05	6.1%	0.41	43.5%	7.5%	
DTE Energy	10.1%	0.43	6.6%	0.04	6.2%	0.53	43.5%	6.5%	
Eastern Utilities	10.7%	0.48	6.6%	0.04	6.2%	0.47	43.5%	7.1%	
GPU Inc.	10.6%	0.43	6.6%	0.02	6.2%	0.55	43.5%	6.6%	
New England Elect.	9.5%	0.48	6.2%	0.04	6.1%	0.49	43.5%	6.4%	
OGE Energy	9.5%	0.51	6.2%	0.03	6.0%	0.46	43.5%	6.6%	
Pinnacle West	9.6%	0.40	6.6%	0.06	6.2%	0.55	43.5%	6.1%	
PP&L Resources	9.5%	0.43	6.6%	0.07	6.1%	0.51	43.5%	6.2%	
Average	10.1%	0.45	6.5%	0.05	6.1%	0.50	43.5%	6.6%	50

SUMMARY								
Weighted US Ave	10.5%	0.53	6.5%	0.04	6.1%	0.43	43.5%	7.4%
Weighted Can/US	10.2%	0.49	6.3%	0.07	6.1%	0.44	43.5%	6.9%
Per Board	9.5%	0.49	6.3%	0.07	6.1%	0.44	43.5%	6.6%

SUMMARY									
Weighted US Ave	10.5%	0.45	6.5%	0.05	6.1%	0.50	43.5%	6.8%	57
Weighted Can/US	10.2%	0.41	6.3%	0.08	6.1%	0.51	43.5%	6.4%	51
Per Board	9.5%	0.41	6.3%	0.08	6.1%	0.51	43.5%	6.16%	28

(Note: Board used high end of equity rate of return due to lower preferred ratio and preferred cost rate)

TRANSALTA FAIR RETURN 1999— INTEGRATED
($Million)

(MYRB = Mid-Year Rate Base)

INTEGRATED 1999	Per TransAlta				Per Board				Per Board				Per Board			
	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $
Traditional Method	48.50%	1396.2	8.19%	114.4	50.50%	1453.8	8.10%	117.8	49.50%	1425.0	8.15%	116.1	48.50%	1396.2	8.19%	114.4
	9.50%	273.5	8.12%	22.2	9.50%	273.5	8.12%	22.2	9.50%	273.5	8.12%	22.2	9.50%	273.5	8.12%	22.2
	42.00%	1209.1	10.64%	128.7	40.00%	1151.5	9.40%	108.2	41.00%	1180.3	9.25%	109.2	42.00%	1209.1	9.11%	110.1
Return	100.00%	2878.8	**9.21%**	265.2	100.00%	2878.8	**8.62%**	248.2	100.00%	2878.8	**8.60%**	247.5	100.00%	2878.8	**8.57%**	246.7
Differential																
Income Tax 43.5%				116.1				100.4				101.1				101.9
Return & Income Tax				381.4				348.6				348.6				348.6
Fixed Tax Adjustment				61.5				38.7				38.7				38.7
Fair Return & Tax				**442.9**				**387.3**				**387.3**				**387.3**
ATWACC Method	48.50%	1396.2	5.96%	47.0	50.50%	1453.8	5.96%	49.0	49.50%	1425.0	5.96%	48.0	48.50%	1396.2	5.96%	47.0
	9.50%	273.5	7.60%	20.8	9.50%	273.5	7.60%	20.8	9.50%	273.5	7.60%	20.8	9.50%	273.5	7.60%	20.8
	42.00%	1209.1	10.64%	128.7	40.00%	1151.5	9.40%	108.2	41.00%	1180.3	9.25%	109.2	42.00%	1209.1	9.11%	110.1
ATWACC (current)	100.00%	2878.8	**6.82%**	196.5	100.00%	2878.8	**6.18%**	177.9	100.00%	2878.8	**6.18%**	177.9	100.00%	2878.8	**6.18%**	177.9
	48.50%	1396.2	8.19%	64.6	50.50%	1453.8	8.10%	66.6	49.50%	1425.0	8.15%	65.59	48.50%	1396.2	8.19%	64.6
	9.50%	273.5	8.12%	22.2	9.50%	273.5	8.12%	22.2	9.50%	273.5	8.12%	22.20	9.50%	273.5	8.12%	22.2
	42.00%	1209.1	10.64%	128.7	40.00%	1151.5	9.40%	108.2	41.00%	1180.3	9.25%	109.18	42.00%	1209.1	9.11%	110.1
ATWACC (embedded)	100.00%	2878.8	**7.48%**	215.5	100.00%	2878.8	**6.84%**	197.0	100.00%	2878.8	**6.84%**	196.96	100.00%	2878.8	**6.84%**	**197.0**
ATWACC Return & Tax		2878.8	**13.25%**	381.4		2878.8	**12.11%**	348.6		2878.8	**12.11%**	348.6		2878.8	**12.11%**	348.6
Fixed Tax Adjustment				61.5				38.7				38.7				38.7
Fair Return & Tax				**442.9**				**387.3**				**387.3**				**387.3**
Before Tax Interest Coverage				**3.87**				**3.29**				**3.34**				**3.39**
After Tax Interest Coverage				**2.32**				**2.11**				**2.13**				**2.16**

Source: Exhibit 59

(Note: The Board, for simplicity, has used the current cost of debt for any additional debt required in order to arrive at the revised embedded cost of debt)

TRANSALTA FAIR RETURN 1999 — GENCO
($Million)

GENCO 1999	Per TransAlta				Per Board				Per Board				Per Board			
	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $
Traditional Method	48.50%	865.9	8.19%	70.9	51.50%	919.4	8.10%	74.5	50.50%	901.6	8.15%	73.4	49.50%	883.7	8.19%	72.4
	9.50%	169.6	8.12%	13.8	9.50%	169.6	8.12%	13.8	9.50%	169.6	8.12%	13.8	9.50%	169.6	8.12%	13.8
	42.00%	749.8	10.47%	78.5	39.00%	696.3	9.40	65.5	40.00%	714.1	9.25%	66.1	41.0%	732.0	9.11%	66.7
Return	100.00%	1785.3	**9.14%**	163.2	100.00%	1785.3	**8.61%**	153.7	100.00%	1785.3	**8.59%**	153.3	100.00%	1785.3	**8.56%**	152.8
Differential 1.00%																
Income Tax 43.5%				71.1				61.0				61.5				61.9
Return & Income Tax				234.3				214.7				214.7				214.7
Fixed Tax Adjustment				22.4				16.7				16.7				16.7
Fair Return & Tax				**256.7**				**231.4**				**231.4**				**231.4**
ATWACC Method	48.50%	865.9	5.96%	29.2	51.50%	919.4	5.96%	31.0	50.50%	901.6	5.96%	30.4	49.50%	883.7	5.96%	29.8
	9.50%	169.6	7.60%	12.9	9.50%	169.6	7.60%	12.9	9.50%	169.6	7.60%	12.9	9.50%	169.6	7.60%	12.9
	42.00%	749.8	10.47%	78.5	39.00%	696.3	9.40%	65.5	40.00%	714.1	9.25%	66.1	41.00%	732.0	9.11%	66.7
ATWACC (current)	100.00%	1785.3	**6.75%**	120.6	100.00%	1785.3	**6.12%**	109.3	100.00%	1785.3	**6.12%**	109.3	100.00%	1785.3	**6.12%**	109.3
	48.50%	865.9	8.19%	40.1	51.50%	919.4	8.10%	42.1	50.50%	901.6	8.15%	41.5	49.50%	883.7	8.19%	40.9
	9.50%	169.6	8.12%	13.8	9.50%	169.6	8.12%	13.8	9.50%	169.6	8.12%	13.8	9.50%	169.6	8.12%	13.8
	42.00%	749.8	10.47%	78.5	39.00%	696.3	9.40%	65.5	40.00%	714.1	9.25%	66.1	41.00%	732.0	9.11%	66.7
ATWACC (embedded)	100.00%	1785.3	**7.41%**	132.4	100.00%	1785.3	**6.80%**	121.3	100.00%	1785.3	**6.80%**	121.3	100.00%	1785.3	**6.80%**	121.3
ATWACC Return & Tax		1785.3	**13.12%**	**234.3**		1785.3	**12.03%**	214.7		1785.3	**12.03%**	214.7		1785.3	**12.03%**	214.7
Fixed Tax Adjustment				22.4				16.7				16.7				16.7
Fair Return & Tax				**256.7**				**231.4**				**231.4**				**231.4**
Before Tax Interest Coverage				**3.62**				**3.11**				**3.15**				**3.20**
After Tax Interest Coverage				**2.30**				**2.06**				**2.09**				**2.11**

(Note: The Board, for simplicity, has used the current cost of debt for any additional debt required in order to arrive at the revised embedded cost of debt)

TRANSALTA FAIR RETURN 1999 — TRANSCO
($Million)

TRANSCO 1999	Per TransAlta				Per Board				Per Board				Per Board			
	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $
Traditional Method	48.50%	322.2	8.19%	26.4	56.50%	375.3	8.11%	30.4	55.50%	368.7	8.15%	30.1	54.50%	362.0	8.19%	29.7
	9.50%	63.1	8.12%	5.1	9.50%	63.1	8.12%	5.1	9.50%	63.1	8.12%	5.1	9.50%	63.1	8.12%	5.1
	42.00%	279.0	9.28%	25.9	34.00%	225.9	9.42%	21.3	35.00%	232.5	9.25%	21.5	36.0%	239.1	9.09%	21.7
Return	100.00%	664.3	**8.64%**	57.4	100.00%	664.3	**8.56%**	56.9	100.00%	664.3	**8.53%**	56.7	100.00%	664.3	**8.51%**	56.5
Differential 6.00%																
Income Tax 43.5%				23.9				20.3				20.5				20.7
Return & Income Tax				81.3				77.2				77.2				77.2
Fixed Tax Adjustment				11.1				7.8				7.8				7.8
Fair Return & Tax				**92.4**				**85.0**				**85.0**				**85.0**
ATWACC Method	48.50%	322.2	5.96%	10.8	56.50%	375.3	5.96%	12.6	55.50%	368.7	5.96%	12.4	54.50%	362.0	5.96%	12.2
	9.50%	63.1	7.60%	4.8	9.50%	63.1	7.60%	4.8	9.50%	63.1	7.60%	4.8	9.50%	63.1	7.60%	4.8
	42.00%	279.0	9.28%	25.9	34.00%	225.9	9.42%	21.3	35.00%	232.5	9.25%	21.5	36.00%	239.1	9.09%	21.7
ATWACC (current)	100.00%	664.3	**6.25%**	41.5	100.00%	664.3	**5.83%**	38.7	100.00%	664.3	**5.83%**	38.7	100.00%	664.3	**5.83%**	38.7
	48.50%	322.2	8.19%	14.9	56.50%	375.3	8.11%	17.2	55.50%	368.7	8.15%	17.0	54.50%	362.0	8.19%	16.8
	9.50%	63.1	8.12%	5.1	9.50%	63.1	8.12%	5.1	9.50%	63.1	8.12%	5.1	9.50%	63.1	8.12%	5.1
	42.00%	279.0	9.28%	25.9	34.00%	225.9	9.42%	21.3	35.00%	232.5	9.25%	21.5	36.00%	239.1	9.09%	21.7
ATWACC (embedded)	100.00%	664.3	**6.91%**	45.9	100.00%	664.3	**6.56%**	43.6	100.00%	664.3	**6.56%**	43.6	100.00%	664.3	**6.56%**	43.6
ATWACC Return & Tax		664.3	**12.24%**	**81.3**		664.3	**11.62%**	77.2		664.3	**11.62%**	77.2		664.3	**11.62%**	77.2
Fixed Tax Adjustment				11.1				7.8				7.8				7.8
Fair Return & Tax				**92.4**				**85.0**				**85.0**				**85.0**
Before Tax Interest Coverage				**3.50**				**2.79**				**2.83**				**2.87**
After Tax Interest Coverage				**2.18**				**1.87**				**1.89**				**1.91**

(Note: The Board, for simplicity, has used the current cost of debt for any additional debt required in order to arrive at the revised embedded cost of debt)

TRANSALTA FAIR RETURN 1999 — DISCO
($Million)

DISCO 1999	Per TransAlta				Per Board				Per Board				Per Board			
	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $
Traditional Method	48.50%	208.2	8.19%	17.1	37.05%	159.0	8.07%	12.8	36.05%	154.7	8.13%	12.6	35.05%	150.5	8.19%	12.3
	9.50%	40.8	8.12%	3.3	9.50%	40.8	8.12%	3.3	9.50%	40.8	8.12%	3.3	9.50%	40.8	8.12%	3.3
	42.00%	180.3	13.45%	24.2	53.45%	229.4	9.36%	21.5	54.45%	233.7	9.25%	21.6	55.45%	238.0	9.14%	21.8
Return	100.00%	429.2	**10.39%**	44.6	100.00%	429.2	**8.76%**	37.6	100.00%	429.2	**8.74%**	37.5	100.00%	429.2	**8.71%**	37.4
Differential 13.45%																
Income Tax 43.5%				21.2				19.1				19.2				19.3
Return & Income Tax				65.8				56.7				56.7				56.7
Fixed Tax Adjustment				28.0				14.2				14.2				14.2
Fair Return & Tax				**93.8**				**70.9**				**70.9**				**70.9**
ATWACC Method	48.50%	208.2	5.96%	7.0	37.05%	159.0	5.96%	5.4	36.05%	154.7	5.96%	5.2	35.05%	150.5	5.96%	5.1
	9.50%	40.8	7.60%	3.1	9.50%	40.8	7.60%	3.1	9.50%	40.8	7.60%	3.1	9.50%	40.8	7.60%	3.1
	42.00%	180.3	13.45%	24.2	53.45%	229.4	9.36%	21.5	54.45%	233.7	9.25%	21.6	55.45%	238.0	9.14%	21.8
ATWACC (current)	100.00%	429.2	**8.00%**	34.4	100.00%	429.2	**6.97%**	29.9	100.00%	429.2	**6.97%**	29.9	100.00%	429.2	**6.97%**	29.9
	48.50%	208.2	8.19%	9.6	37.05%	159.0	8.07%	7.3	36.05%	154.7	8.13%	7.1	35.05%	150.5	8.19%	7.0
	9.50%	40.8	8.12%	3.3	9.50%	40.8	8.12%	3.3	9.50%	40.8	8.12%	3.3	9.50%	40.8	8.12%	3.3
	42.00%	180.3	13.45%	24.2	53.45%	229.4	9.36%	21.5	54.45%	233.7	9.25%	21.6	55.45%	238.0	9.14%	21.8
ATWACC (embedded)	100.00%	429.2	**8.66%**	37.2	100.00%	429.2	**7.46%**	32.0	100.00%	429.2	**7.46%**	32.0	100.00%	429.2	**7.46%**	32.0
ATWACC Return & Tax		429.2	**15.33%**	65.8		429.2	**13.21%**	56.7		429.2	**13.21%**	56.7		429.2	**13.21%**	56.7
Fixed Tax Adjustment				28.0				14.2				14.2				14.2
Fair Return & Tax				**93.8**				**70.9**				**70.9**				**70.9**
Before Tax Interest Coverage				**5.50**				**5.52**				**5.64**				**5.75**
After Tax Interest Coverage				**2.62**				**2.93**				**2.98**				**3.03**

(Note: The Board, for simplicity, has used the current cost of debt for any additional debt required in order to arrive at the revised embedded cost of debt)

TRANSALTA FAIR RETURN 2000 — INTEGRATED
($Million)

INTEGRATED 2000	Per TransAlta				Per Board				Per Board				Per Board			
	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $
Traditional Method	48.77%	1384.5	7.74%	107.1	50.77%	1441.3	7.67%	110.5	49.77%	1412.9	7.70%	108.8	48.77%	1384.5	7.74%	107.1
	9.23%	262.0	7.69%	20.2	9.23%	262.0	7.69%	20.2	9.23%	262.0	7.69%	20.2	9.23%	262.0	7.69%	20.2
	42.00%	1192.3	10.61%	126.5	40.00%	1135.5	9.40%	106.7	41.00%	1163.9	9.25%	107.7	42.00%	1192.3	9.11%	108.6
Return	100.00%	2838.8	**8.94%**	253.8	100.00%	2838.8	**8.36%**	237.4	100.00%	2838.8	**8.34%**	236.6	100.00%	2838.8	**8.31%**	235.9
Differential																
Income Tax 43.5%				112.9				97.7				98.4				99.1
Return & Income Tax				366.6				335.0				335.0				335.0
Fixed Tax Adjustment				73.6				48.0				48.0				48.0
Fair Return & Tax				**440.2**				**383.0**				**383.0**				**383.0**
ATWACC Method	48.77%	1404.0	5.96%	47.3	50.77%	1461.6	5.96%	49.2	49.77%	1432.8	5.96%	48.2	48.77%	1404.0	5.96%	47.3
	9.23%	265.7	7.60%	20.2	9.23%	265.7	7.60%	20.2	9.23%	265.7	7.60%	20.2	9.23%	265.7	7.60%	20.2
	42.00%	1209.1	10.61%	128.3	40.00%	1151.5	9.40%	108.2	41.00%	1180.3	9.25%	109.2	42.00%	1209.1	9.11%	110.1
ATWACC (current)	100.00%	2878.8	**6.80%**	195.7	100.00%	2878.8	**6.17%**	177.6	100.00%	2878.8	**6.17%**	177.6	100.00%	2878.8	**6.17%**	177.6
	48.77%	1404.0	7.74%	61.4	50.77%	1461.6	7.67%	63.3	49.77%	1432.8	7.70%	62.34	48.77%	1404.0	7.74%	61.4
	9.23%	265.7	7.69%	20.4	9.23%	265.7	7.69%	20.4	9.23%	265.7	7.69%	20.44	9.23%	265.7	7.69%	20.4
	42.00%	1209.1	10.61%	128.3	40.00%	1151.5	9.40%	108.2	41.00%	1180.3	9.25%	109.18	42.00%	1209.1	9.11%	110.1
ATWACC (embedded)	100.00%	2878.8	**7.30%**	210.1	100.00%	2878.8	**6.67%**	192.0	100.00%	2878.8	**6.67%**	191.96	100.00%	2878.8	**6.67%**	192.0
ATWACC Return &Tax		2838.8	**12.92%**	366.6		2838.8	**11.80%**	335.0		2838.8	**11.80%**	335.0		2838.8	**11.80%**	335.0
Fixed Tax Adjust				73.6				48.0				48.0				48.0
Fair Return & Tax				**440.2**				**383.0**				**383.0**				**383.0**
Before Tax Interest Coverage				**4.11**				**3.47**				**3.52**				**3.58**
After Tax Interest Coverage				**2.37**				**2.15**				**2.17**				**2.20**

(Note: The Board, for simplicity, has used the current cost of debt for any additional debt required in order to arrive at the revised embedded cost of debt)

TRANSALTA FAIR RETURN 2000 — GENCO
($Million)

GENCO 2000	Per TransAlta				Per Board				Per Board				Per Board			
	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $
Traditional Method	48.77%	861.4	7.74%	66.6	51.77%	914.4	7.67%	70.1	50.77%	896.7	7.70%	69.1	49.77%	879.0	7.74%	68.0
	9.23%	163.0	7.69%	12.5	9.23%	163.0	7.69%	12.5	9.23%	163.0	7.69%	12.5	9.23%	163.0	7.69%	12.5
	42.00%	741.8	10.46%	77.6	39.00%	688.8	9.40%	64.8	40.00%	706.5	9.25%	65.3	41.0%	724.1	9.11%	65.9
Return	100.00%	1766.2	**8.87%**	156.7	100.00%	1766.2	**8.35%**	147.4	100.00%	1766.2	**8.32%**	147.0	100.00%	1766.2	**8.29%**	146.5
Differential 1.00%																
Income Tax 43.5%				69.4				59.5				60.0				60.4
Return & Income Tax				226.1				206.9				206.9				206.9
Fixed Tax Adjustment				31.0				20.1				20.1				20.1
Fair Return & Tax				**257.1**				**227.0**				**227.0**				**227.0**
ATWACC Method	48.77%	861.4	5.96%	29.0	51.77%	914.4	5.96%	30.8	50.77%	896.7	5.96%	30.2	49.77%	879.0	5.96%	29.6
	9.23%	163.0	7.60%	12.4	9.23%	163.0	7.60%	12.4	9.23%	163.0	7.60%	12.4	9.23%	163.0	7.60%	12.4
	42.00%	741.8	10.46%	77.6	39.00%	688.8	9.40%	64.8	40.00%	706.5	9.25%	65.3	41.00%	724.1	9.11%	65.9
ATWACC (current)	100.00%	1766.2	**6.74%**	119.0	100.00%	1766.2	**6.11%**	107.9	100.00%	1766.2	**6.11%**	107.9	100.00%	1766.2	**6.11%**	107.9
	48.77%	861.4	7.74%	37.7	51.77%	914.4	7.67%	39.6	50.77%	896.7	7.70%	39.0	49.77%	879.0	7.74%	38.4
	9.23%	163.0	7.69%	12.5	9.23%	163.0	7.69%	12.5	9.23%	163.0	7.69%	12.5	9.23%	163.0	7.69%	12.5
	42.00%	741.8	10.46%	77.6	39.00%	688.8	9.40%	64.8	40.00%	706.5	9.25%	65.3	41.00%	724.1	9.11%	65.9
ATWACC (embedded)	100.00%	1766.2	**7.23%**	127.8	100.00%	1766.2	**6.62%**	116.9	100.00%	1766.2	**6.62%**	116.9	100.00%	1766.2	**6.62%**	116.9
ATWACC Return & Tax		1766.2	**12.80%**	**226.1**		1766.2	**11.72%**	206.9		1766.2	**11.72%**	206.9		1766.2	**11.72%**	206.9
Fixed Tax Adjustment				31.0				20.1				20.1				20.1
Fair Return & Tax				**257.1**				**227.0**				**227.0**				**227.0**
Before Tax Interest Coverage				**3.86**				**3.24**				**3.29**				**3.34**
After Tax Interest Coverage				**2.35**				**2.10**				**2.13**				**2.15**

(Note: The Board, for simplicity, has used the current cost of debt for any additional debt required in order to arrive at the revised embedded cost of debt)

TRANSALTA FAIR RETURN 2000 — TRANSCO
($Million)

TRANSCO 2000	Per TransAlta				Per Board				Per Board				Per Board			
	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $
Traditional Method	48.77%	323.1	7.74%	25.0	56.77%	376.0	7.67%	28.9	55.77%	369.4	7.71%	28.5	54.77%	362.8	7.74%	28.1
	9.23%	61.1	7.69%	4.7	9.23%	61.1	7.69%	4.7	9.23%	61.1	7.69%	4.7	9.23%	61.1	7.69%	4.7
	42.00%	278.2	9.27%	25.8	34.00%	225.2	9.42%	21.2	35.00%	231.8	9.25%	21.4	36.0%	238.5	9.09%	21.7
Return	100.00%	662.4	**8.38%**	55.5	100.00%	662.4	**8.27%**	54.8	100.00%	662.4	**8.24%**	54.6	100.00%	662.4	**8.22%**	54.4
Differential 6.00%																
Income Tax 43.5%				23.5				20.0				20.1				20.3
Return & Income Tax				78.9				74.7				74.7				74.7
Fixed Tax Adjustment				12.8				8.3				8.3				8.3
Fair Return & Tax				**91.7**				**83.0**				**83.0**				**83.0**
ATWACC Method	48.77%	323.1	5.96%	10.9	56.77%	376.0	5.96%	12.7	55.77%	369.4	5.96%	12.4	54.77%	362.8	5.96%	12.2
	9.23%	61.1	7.60%	4.6	9.23%	61.1	7.60%	4.6	9.23%	61.1	7.60%	4.6	9.23%	61.1	7.60%	4.6
	42.00%	278.2	9.27%	25.8	34.00%	225.2	9.42%	21.2	35.00%	231.8	9.25%	21.4	36.00%	238.5	9.09%	21.7
ATWACC (current)	100.00%	662.4	**6.24%**	41.3	100.00%	662.4	**5.82%**	38.5	100.00%	662.4	**5.82%**	38.5	100.00%	662.4	**5.82%**	38.5
	48.77%	323.1	7.74%	14.1	56.77%	376.0	7.67%	16.3	55.77%	369.4	7.71%	16.1	54.77%	362.8	7.74%	15.9
	9.23%	61.1	7.69%	4.7	9.23%	61.1	7.69%	4.7	9.23%	61.1	7.69%	4.7	9.23%	61.1	7.69%	4.7
	42.00%	278.2	9.27%	25.8	34.00%	225.2	9.42%	21.2	35.00%	231.8	9.25%	21.4	36.00%	238.5	9.09%	21.7
ATWACC (embedded)	100.00%	662.4	**6.73%**	44.6	100.00%	662.4	**6.38%**	42.2	100.00%	662.4	**6.38%**	42.2	100.00%	662.4	**6.38%**	42.2
ATWACC Return & Tax		662.4	**11.92%**	**78.9**		662.4	**11.28%**	74.7		662.4	**11.28%**	74.7		662.4	**11.28%**	74.7
Fixed Tax Adjustment				12.8				8.3				8.3				8.3
Fair Return & Tax				**91.7**				**83.0**				**83.0**				**83.0**
Before Tax Interest Coverage				**3.67**				**2.88**				**2.92**				**2.96**
After Tax Interest Coverage				**2.22**				**1.90**				**1.92**				**1.94**

(Note: The Board, for simplicity, has used the current cost of debt for any additional debt required in order to arrive at the revised embedded cost of debt)

TRANSALTA FAIR RETURN 2000 — DISCO
($Million)

DISCO 2000	Per TransAlta				Per Board				Per Board				Per Board			
	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $
Traditional Method	48.77%	200.1	7.74%	15.5	37.27%	152.9	7.64%	11.7	36.27%	148.8	7.69%	11.4	35.27%	144.7	7.74%	11.2
	9.23%	37.9	7.69%	2.9	9.23%	37.9	7.69%	2.9	9.23%	37.9	7.69%	2.9	9.23%	37.9	7.69%	2.9
	42.00%	172.3	13.43%	23.1	53.50%	219.5	9.36%	20.5	54.50%	223.6	9.25%	20.7	55.50%	227.7	9.14%	20.8
Return	100.00%	410.2	**10.12%**	41.5	100.00%	410.2	**8.57%**	35.1	100.00%	410.2	**8.54%**	35.0	100.00%	410.2	**8.51%**	34.9
Differential 13.50%																
Income Tax 43.5%				20.1				18.1				18.2				18.3
Return & Income Tax				61.6				53.2				53.2				53.2
Fixed Tax Adjustment				29.8				19.6				19.6				19.6
Fair Return & Tax				**91.4**				**72.8**				**72.8**				**72.8**
ATWACC Method	48.77%	200.1	5.96%	6.7	37.27%	152.9	5.96%	5.1	36.27%	148.8	5.96%	5.0	35.27%	144.7	5.96%	4.9
	9.23%	37.9	7.60%	2.9	9.23%	37.9	7.60%	2.9	9.23%	37.9	7.60%	2.9	9.23%	37.9	7.60%	2.9
	42.00%	172.3	13.43%	23.1	53.50%	219.5	9.36%	20.5	54.50%	223.6	9.25%	20.7	55.50%	227.7	9.14%	20.8
ATWACC (current)	100.00%	410.2	**7.99%**	32.8	100.00%	410.2	**6.96%**	28.6	100.00%	410.2	**6.96%**	28.6	100.00%	410.2	**6.96%**	28.6
	48.77%	200.1	7.74%	8.7	37.27%	152.9	7.64%	6.6	36.27%	148.8	7.69%	6.5	35.27%	144.7	7.74%	6.3
	9.23%	37.9	7.69%	2.9	9.23%	37.9	7.69%	2.9	9.23%	37.9	7.69%	2.9	9.23%	37.9	7.69%	2.9
	42.00%	172.3	13.43%	23.1	53.50%	219.5	9.36%	20.5	54.50%	223.6	9.25%	20.7	55.50%	227.7	9.14%	20.8
ATWACC (embedded)	100.00%	410.2	**8.48%**	34.8	100.00%	410.2	**7.33%**	30.1	100.00%	410.2	**7.33%**	30.1	100.00%	410.2	**7.33%**	30.1
ATWACC Return & Tax		410.2	**15.01%**	**61.6**		410.2	**12.97%**	53.2		410.2	**12.97%**	53.2		410.2	**12.97%**	53.2
Fixed Tax Adjustment				29.8				19.6				19.6				19.6
Fair Return & Tax				**91.4**				**72.8**				**72.8**				**72.8**
Before Tax Interest Coverage				**5.90**				**6.23**				**6.36**				**6.50**
After Tax Interest Coverage				**2.68**				**3.01**				**3.06**				**3.12**

(Note: The Board, for simplicity, has used the current cost of debt for any additional debt required in order to arrive at the revised embedded cost of debt)

EPGI FAIR RETURN 1999
($Million)

GENCO 1999	Per EPGI				Per Board				Per Board				Per Board			
	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $
Traditional Method	54.00%	683.3	10.22%	69.8	57.00%	721.3	10.07%	72.6	56.00%	708.6	10.14%	71.9	55.00%	696.0	10.22%	71.1
	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	8.12%	0.0	0.00%	0.0	8.12%	0.0
	46.00%	582.1	11.00%	64.0	43.00%	544.1	9.33%	50.7	44.00%	556.8	9.25%	51.5	45.0%	569.4	9.18%	52.3
Return	100.00%	1265.4	**10.58%**	133.9	100.00%	1265.4	**9.75%**	123.4	100.00%	1265.4	**9.75%**	123.4	100.00%	1265.4	**9.75%**	123.4
Income Tax				0.0				0.0				0.0				0.0
Return & Income Tax				133.9				123.4				123.4				123.4
Fixed Tax Adjustment				0.0				0.0				0.0				0.0
Fair Return & Tax				**133.9**				**123.4**				**123.4**				**123.4**
ATWACC Method	54.00%	683.3	5.96%	40.7	57.00%	721.3	5.96%	43.0	56.00%	708.6	5.96%	42.2	55.00%	696.0	5.96%	41.5
	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0
	46.00%	582.1	11.00%	64.0	43.00%	544.1	9.33%	50.7	44.00%	556.8	9.25%	51.5	45.00%	569.4	9.18%	52.3
ATWACC (current)	100.00%	1265.4	**8.28%**	104.8	100.00%	1265.4	**7.41%**	93.7	100.00%	1265.4	**7.41%**	93.7	100.00%	1265.4	**7.41%**	93.7
	54.00%	683.3	10.22%	69.8	57.00%	721.3	10.07%	72.6	56.00%	708.6	10.14%	71.9	55.00%	696.0	10.22%	71.1
	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	8.12%	0.0	0.00%	0.0	8.12%	0.0
	46.00%	582.1	11.00%	64.0	43.00%	544.1	9.33%	50.7	44.00%	556.8	9.25%	51.5	45.00%	569.4	9.18%	52.3
ATWACC (embedded)	100.00%	1265.4	**10.58%**	133.9	100.00%	1265.4	**9.75%**	123.4	100.00%	1265.4	**9.75%**	123.4	100.00%	1265.4	**9.75%**	123.4
ATWACC Return &Tax		1265.4	10.58%	**133.9**		1265.4	9.75%	123.4		1265.4	9.75%	123.4		1265.4	9.75%	123.4
Fixed Tax Adjustment				0.0				0.0				0.0				0.0
Fair Return & Tax				**133.9**				**123.4**				**123.4**				**123.4**
Before Tax Interest Coverage				**1.92**				**1.70**				**1.72**				**1.73**
After Tax Interest Coverage				**1.92**				**1.70**				**1.72**				**1.73**

(Note: The Board, for simplicity, has used the current cost of debt for any additional debt required in order to arrive at the revised embedded cost of debt)

EPTI FAIR RETURN 1999
($Million)

TRANSCO 1999	Per EPTI				Per Board				Per Board				Per Board			
	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $
Traditional Method	64.70%	97.2	10.08%	9.8	66.00%	99.2	9.96%	9.9	65.00%	97.7	10.02%	9.8	64.00%	96.2	10.08%	9.7
	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0
	35.30%	53.1	11.00%	5.8	34.00%	51.1	9.35%	4.8	35.00%	52.6	9.25%	4.9	36.0%	54.1	9.16%	5.0
Return	100.00%	150.3	**10.40%**	15.6	100.00%	150.3	**9.75%**	14.7	100.00%	150.3	**9.75%**	14.7	100.00%	150.3	**9.75%**	14.7
Income Tax				0.0				0.0				0.0				0.0
Return & Income Tax				15.6				14.7				14.7				14.7
Fixed Tax Adjustment				0.0				0.0				0.0				0.0
Fair Return & Tax				**15.6**				**14.7**				**14.7**				**14.7**
ATWACC Method	64.70%	97.2	5.96%	5.8	66.00%	99.2	5.96%	5.9	65.00%	97.7	5.96%	5.8	64.00%	96.2	5.96%	5.7
	0.00%	0.0	7.60%	0.0	0.00%	0.0	7.60%	0.0	0.00%	0.0	7.60%	0.0	0.00%	0.0	7.60%	0.0
	35.30%	53.1	11.00%	5.8	34.00%	51.1	9.35%	4.8	35.00%	52.6	9.25%	4.9	36.00%	54.1	9.16%	5.0
ATWACC (current)	100.00%	150.3	**7.74%**	11.6	100.00%	150.3	**7.11%**	10.7	100.00%	150.3	**7.11%**	10.7	100.00%	150.3	**7.11%**	10.7
	64.70%	97.2	10.08%	9.8	66.00%	99.2	9.96%	9.9	65.00%	97.7	10.02%	9.8	64.00%	96.2	10.08%	9.7
	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0
	35.30%	53.1	11.00%	5.8	34.00%	51.1	9.35%	4.8	35.00%	52.6	9.25%	4.9	36.00%	54.1	9.16%	5.0
ATWACC (embedded)	100.00%	150.3	**10.40%**	15.6	100.00%	150.3	**9.75%**	14.7	100.00%	150.3	**9.75%**	14.7	100.00%	150.3	**9.75%**	14.7
ATWACC Return & Tax		150.3	10.40%	15.6		150.3	9.75%	14.7		150.3	9.75%	14.7		150.3	9.75%	14.7
Fixed Tax Adjustment				0.0				0.0				0.0				0.0
Fair Return & Tax				**15.6**				**14.7**				**14.7**				**14.7**
Before Tax Interest Coverage				**1.60**				**1.48**				**1.50**				**1.51**
After Tax Interest Coverage				**1.60**				**1.48**				**1.50**				**1.51**

(Note: The Board, for simplicity, has used the current cost of debt for any additional debt required in order to arrive at the revised embedded cost of debt)

EPGI FAIR RETURN 2000
($Million)

GENCO 2000	Per EPGI				Per Board				Per Board				Per Board			
	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $
Traditional Method	51.20%	635.6	10.19%	64.8	57.00%	707.6	10.04%	71.1	56.00%	695.2	10.11%	70.3	55.00%	682.8	10.19%	69.6
	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0
	48.80%	605.8	11.00%	66.6	43.00%	533.8	9.33%	49.8	44.00%	546.2	9.25%	50.5	45.0%	558.6	9.18%	51.3
Return	100.00%	1241.4	**10.59%**	131.4	100.00%	1241.4	**9.73%**	120.8	100.00%	1241.4	**9.73%**	120.8	100.00%	1241.4	**9.73%**	120.8
Income Tax				0.0				0.0				0.0				0.0
Return & Income Tax				131.4				120.8				120.8				120.8
Fixed Tax Adjustment				0.0				0.0				0.0				0.0
Fair Return & Tax				**131.4**				**120.8**				**120.8**				**120.8**
ATWACC Method	51.20%	635.6	5.96%	37.9	57.00%	707.6	5.96%	42.2	56.00%	695.2	5.96%	41.4	55.00%	682.8	5.96%	40.7
	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0
	48.80%	605.8	11.00%	66.6	43.00%	533.8	9.33%	49.8	44.00%	546.2	9.25%	50.5	45.00%	558.6	9.18%	51.3
ATWACC (current)	100.00%	1241.4	**8.42%**	104.5	100.00%	1241.4	**7.41%**	92.0	100.00%	1241.4	**7.41%**	92.0	100.00%	1241.4	**7.41%**	92.0
	51.20%	635.6	10.19%	64.8	57.00%	707.6	10.04%	71.1	56.00%	695.2	10.11%	70.3	55.00%	682.8	10.19%	69.6
	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0
	48.80%	605.8	11.00%	66.6	43.00%	533.8	9.33%	49.8	44.00%	546.2	9.25%	50.5	45.00%	558.6	9.18%	51.3
ATWACC (embedded)	100.00%	1241.4	**10.59%**	131.4	100.00%	1241.4	**9.73%**	120.8	100.00%	1241.4	**9.73%**	120.8	100.00%	1241.4	**9.73%**	120.8
ATWACC Return & Tax		1241.4	**10.59%**	131.4		1241.4	**9.73%**	120.8		1241.4	**9.73%**	120.8		1241.4	**9.73%**	120.8
Fixed Tax Adjust				0.0				0.0				0.0				0.0
Fair Return & Tax				**131.4**				**120.8**				**120.8**				**120.8**
Before Tax Interest Coverage				**2.03**				**1.70**				**1.72**				**1.74**
After Tax Interest Coverage				**2.03**				**1.70**				**1.72**				**1.74**

(Note: The Board, for simplicity, has used the current cost of debt for any additional debt required in order to arrive at the revised embedded cost of debt)

EPTI FAIR RETURN 2000
($Million)

TRANSCO 2000	Per EPTI				Per Board				Per Board				Per Board			
	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $	Capital Structure	MYRB $	Cost Rate	Return $
Traditional Method	65.90%	98.9	9.44%	9.3	66.00%	99.0	9.33%	9.2	65.00%	97.5	9.39%	9.2	64.00%	96.0	9.44%	9.1
	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0
	34.10%	51.2	11.00%	5.6	34.00%	51.0	9.35%	4.8	35.00%	52.5	9.25%	4.9	36.00%	54.0	9.16%	4.9
Return	100.00%	150.0	**9.97%**	15.0	100.00%	150.0	**9.34%**	14.0	100.00%	150.0	**9.34%**	14.0	100.00%	150.0	**9.34%**	14.0
Income Tax				0.0				0.0				0.0				0.0
Return & Income Tax				15.0				14.0				14.0				14.0
Fixed Tax Adjustment				0.0				0.0				0.0				0.0
Fair Return & Tax				**15.0**				**14.0**				**14.0**				**14.0**
ATWACC Method	65.90%	98.9	5.96%	5.9	66.00%	99.0	5.96%	5.9	65.00%	97.5	5.96%	5.8	64.00%	96.0	5.96%	5.7
	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0
	34.10%	51.2	11.00%	5.6	34.00%	51.0	9.35%	4.8	35.00%	52.5	9.25%	4.9	36.00%	54.0	9.16%	4.9
ATWACC (current)	100.00%	150.0	**7.68%**	11.5	100.00%	150.0	**7.11%**	10.7	100.00%	150.0	**7.11%**	10.7	100.00%	150.0	**7.11%**	10.7
	65.90%	98.9	9.44%	9.3	66.00%	99.0	9.33%	9.2	65.00%	97.5	9.39%	9.2	64.00%	96.0	9.44%	9.1
	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0
	34.10%	51.2	11.00%	5.6	34.00%	51.0	9.35%	4.8	35.00%	52.5	9.25%	4.9	36.00%	54.0	9.16%	4.9
ATWACC (embedded)	100.00%	150.0	**9.97%**	15.0	100.00%	150.0	**9.34%**	14.0	100.00%	150.0	**9.34%**	14.0	100.00%	150.0	**9.34%**	14.0
ATWACC Return & Tax		150.0	**9.97%**	15.0		150.0	**9.34%**	14.0		150.0	**9.34%**	14.0		150.0	**9.34%**	14.0
Fixed Tax Adjust				0.0				0.0				0.0				0.0
Fair Return & Tax				**15.0**				**14.0**				**14.0**				**14.0**
Before Tax Interest Coverage				**1.60**				**1.52**				**1.53**				**1.55**
After Tax Interest Coverage				**1.60**				**1.52**				**1.53**				**1.55**

(Note: The Board, for simplicity, has used the current cost of debt for any additional debt required in order to arrive at the revised embedded cost of debt)

TRANSALTA 1999 INCOME TAX — PER TRANSALTA
($ Million)

	GENCO			TRANSCO			DISCO			TOTAL		
	Federal	Provincial	Total	Federal	Provincial	Total	Federal	Provincial	Total	Federal	Provincial	Total
Preferred Return	13.4	13.4	13.4	5.3	5.3	5.3	3.5	3.5	3.5	22.2	22.2	22.2
Common Return	78.5	78.5	78.5	25.9	25.9	25.9	24.2	24.2	24.2	128.6	128.6	128.6
Total Equity	91.9	91.9	91.9	31.2	31.2	31.2	27.7	27.7	27.7	150.8	150.8	150.8
Tax Rate	28%	15.5%	43.5%	28%	15.5%	43.5%	28%	15.5%	43.5%	28%	15.5%	43.5%
Book Income Tax	**45.5**	**25.2**	**70.8**	**15.5**	**8.6**	**24.0**	**13.7**	**7.6**	**21.3**	**74.7**	**41.4**	**116.1**
Perm difference	14.8	14.8		3.9	3.9		3.4	3.4		22.1	22.1	
Resource Allow	-9.0	-8.2		0	0		0	0		-9	-8.2	
Sub-Total	5.8	6.6		3.9	3.9		3.4	3.4		13.1	13.9	
Tax on Perm Diff	1.6	1.0	2.6	1.1	0.6	1.7	1.0	0.5	1.5	3.7	2.2	5.8
Tax on Perm Tax	1.3	0.7	2.0	0.8	0.5	1.3	0.7	0.4	1.1	2.9	1.6	4.5
Total Perm Diff Tax	2.9	1.7	4.7	1.9	1.1	3.0	1.7	0.9	2.6	6.6	3.8	10.3
Timing Difference	7.6	20.0		6.7	8.5		27.9	28.5		42.2	57.0	
RA Timing Diff	3.8											
Total Timing Diff	11.4	20.0		6.7	8.5		27.9	28.5		42.2	57.0	
Tax on Timing Diff	3.2	3.1	6.3	1.9	1.3	3.2	7.8	4.4	12.2	12.9	8.8	21.7
Tax on Timing Tax	3.1	1.7	4.8	1.6	0.9	2.5	6.1	3.4	9.4	10.8	6.0	16.7
Total Timing Tax	6.3	4.8	11.1	3.5	2.2	5.7	13.9	7.8	21.6	23.6	14.8	38.4
Lge Corp Tax (LCT)			3.7			1.4			2.1			7.2
Tax on LCT	1.8	1.0	2.8	0.7	0.4	1.1	1.0	0.6	1.6	3.6	2.0	5.5
Total LCT	1.8	1.0	6.5	0.7	0.4	2.5	1.0	0.6	3.7	3.6	2.0	12.7
Fixed Tax Adj	**11.1**	**7.6**	**22.4**	**6.1**	**3.6**	**11.1**	**16.6**	**9.3**	**28.0**	**33.8**	**20.5**	**61.5**
Total Income Tax	**56.6**	**32.8**	**93.1**	**21.5**	**12.2**	**35.2**	**30.3**	**16.9**	**49.3**	**108.5**	**61.9**	**177.6**
Per Exhibit 59			**93.7**			**35.8**			**50.1**			**179.6**

TRANSALTA 1999 INCOME TAX — PER BOARD
($ Million)

	GENCO			TRANSCO			DISCO			TOTAL		
	Federal	Provincial	Total	Federal	Provincial	Total	Federal	Provincial	Total	Federal	Provincial	Total
Preferred Return	13.8	13.8	13.8	5.1	5.1	5.1	3.3	3.3	3.3	22.2	22.2	22.2
Common Return	66.1	66.1	66.1	21.5	21.5	21.5	21.6	21.6	21.6	109.2	109.2	109.2
Total Equity	79.9	79.9	79.9	26.6	26.6	26.6	24.9	24.9	24.9	131.4	131.4	131.4
Tax Rate	28%	15.5%	43.5%	28%	15.5%	43.5%	28%	15.5%	43.5%	28%	15.5%	43.5%
Book Income Tax	**39.6**	**21.9**	**61.5**	**13.2**	**7.3**	**20.5**	**12.3**	**6.8**	**19.2**	**65.1**	**36.0**	**101.2**
Perm difference	14.8	14.8		3.9	3.9		3.4	3.4		22.1	22.1	
Resource Allow	-9.0	-8.2		0	0		0	0		-9	-8.2	
Sub-Total	5.8	6.6		3.9	3.9		3.4	3.4		13.1	13.9	
Tax on Perm Diff	1.6	1.0	2.6	1.1	0.6	1.7	1.0	0.5	1.5	3.7	2.2	5.8
Tax on Perm Tax	1.3	0.7	2.0	0.8	0.5	1.3	0.7	0.4	1.1	2.9	1.6	4.5
Total Perm Diff Tax	2.9	1.7	4.7	1.9	1.1	3.0	1.7	0.9	2.6	6.6	3.8	10.3
Timing Difference	0.0	20.0		0.0	8.5		0.0	28.5		0.0	57.0	
RA Timing Diff	3.8											
Total Timing Diff	0.0	20.0		0.0	8.5		0.0	28.5		0.0	57.0	
Tax on Timing Diff	0.0	3.1	3.1	0.0	1.3	1.3	0.0	4.4	4.4	0.0	8.8	8.8
Tax on Timing Tax	1.5	0.9	2.4	0.7	0.4	1.0	2.2	1.2	3.4	4.4	2.4	6.8
Total Timing Tax	1.5	4.0	5.5	0.7	1.7	2.3	2.2	5.6	7.8	4.4	11.3	15.6
Lge Corp Tax (LCT)			3.7			1.4			2.1			7.2
Tax on LCT	1.8	1.0	2.8	0.7	0.4	1.1	1.0	0.6	1.6	3.6	2.0	5.5
Total LCT	1.8	1.0	6.5	0.7	0.4	2.5	1.0	0.6	3.7	3.6	2.0	12.7
Fixed Tax Adj	**6.3**	**6.7**	**16.7**	**3.3**	**3.1**	**7.8**	**4.9**	**17.1**	**14.2**	**14.5**	**17.0**	**38.7**
Total Income Tax	**45.9**	**28.6**	**78.2**	**16.5**	**10.4**	**28.3**	**17.3**	**14.0**	**33.3**	**79.6**	**53.0**	**139.3**

TRANSALTA 2000 INCOME TAX – PER TRANSALTA
($ Million)

	GENCO			TRANSCO			DISCO			TOTAL		
	Federal	Provincial	Total	Federal	Provincial	Total	Federal	Provincial	Total	Federal	Provincial	Total
Preferred Return	12.7	12.7	12.7	5.3	5.3	5.3	3.4	3.4	3.4	21.4	21.4	21.4
Common Return	77.6	77.6	77.6	25.8	25.8	25.8	23.1	23.1	23.1	126.5	126.5	126.5
Total Equity	90.3	90.3	90.3	31.1	31.1	31.1	26.5	26.5	26.5	147.9	147.9	147.9
Tax Rate	28%	15.5%	43.5%	28%	15.5%	43.5%	28%	15.5%	43.5%	28%	15.5%	43.5%
Book Income Tax	**44.8**	**24.8**	**69.5**	**15.4**	**8.5**	**23.9**	**13.1**	**7.3**	**20.4**	**73.3**	**40.6**	**113.9**
Perm difference	14.8	14.8		3.9	3.9		3.4	3.4		22.1	22.1	
Resource Allow	-6.6	-8.7		0.0	0.0		0.0	0.0		-6.6	-8.7	
Sub-Total	8.2	6.1		3.9	3.9		3.4	3.4		15.5	13.4	
Tax on Perm Diff	2.3	0.9	3.2	1.1	0.6	1.7	1.0	0.5	1.5	4.3	2.1	6.4
Tax on Perm Tax	1.6	0.9	2.5	0.8	0.5	1.3	0.7	0.4	1.1	3.2	1.8	4.9
Total Perm Diff Tax	3.9	1.8	5.7	1.9	1.1	3.0	1.7	0.9	2.6	7.5	3.8	11.4
Timing Difference	19.8	28.5	48.3	9.0	10.3	19.3	30.6	31.0	61.6	59.4	69.8	
RA Timing Diff	2.2											
Total Timing Diff	22.0	28.5		9.0	10.3		30.6	31.0		59.4	69.8	
Tax on Timing Diff	6.2	4.4	10.6	2.5	1.6	4.1	8.6	4.8	13.4	17.2	10.8	28.1
Tax on Timing Tax	5.2	2.9	8.1	2.0	1.1	3.2	6.6	3.7	10.3	13.9	7.7	21.6
Total Timing Tax	11.4	7.3	18.7	4.6	2.7	7.3	15.2	8.5	23.7	31.2	18.5	49.7
Lge Corp Tax (LCT)			3.7			1.4			2.0			7.1
Tax on LCT	1.8	1.0	2.8	0.7	0.4	1.1	1.0	0.5	1.5	3.5	1.9	5.5
Total LCT	1.8	1.0	6.5	0.7	0.4	2.5	1.0	0.5	3.5	3.5	1.9	12.6
Fixed Tax Adj	**17.1**	**10.2**	**31.0**	**7.2**	**4.2**	**12.8**	**17.9**	**10.0**	**29.8**	**42.2**	**24.3**	**73.6**
Total Income Tax	**61.9**	**34.9**	**100.5**	**22.6**	**12.7**	**36.7**	**31.0**	**17.2**	**50.2**	**115.5**	**64.9**	**187.5**
Per Exhibit 59			**100.1**			**37.2**			**50.9**			**188.2**

TRANSALTA 2000 INCOME TAX – PER BOARD
($ Million)

	GENCO			TRANSCO			DISCO			TOTAL		
	Federal	Provincial	Total	Federal	Provincial	Total	Federal	Provincial	Total	Federal	Provincial	Total
Preferred Return	12.5	12.5	12.5	4.7	4.7	4.7	2.9	2.9	2.9	20.1	20.1	20.1
Common Return	65.3	65.3	65.3	21.4	21.4	21.4	20.9	20.9	20.9	107.6	107.6	107.6
Total Equity	77.8	77.8	77.8	26.1	26.1	26.1	23.8	23.8	23.8	127.7	127.7	127.7
Tax Rate	28%	15.5%	43.5%	28%	15.5%	43.5%	28%	15.5%	43.5%	28%	15.5%	43.5%
Book Income Tax	**38.6**	**21.3**	**59.9**	**12.9**	**7.2**	**20.1**	**11.8**	**6.5**	**18.3**	**63.3**	**35.0**	**98.3**
Perm difference	14.8	14.8		3.9	3.9		3.4	3.4		22.1	22.1	
Resource Allow	-6.6	-8.7		0.0	0.0		0.0	0.0		-6.6	-8.7	
Sub-Total	8.2	6.1		3.9	3.9		3.4	3.4		15.5	13.4	
Tax on Perm Diff	2.3	0.9	3.2	1.1	0.6	1.7	1.0	0.5	1.5	4.3	2.1	6.4
Tax on Perm Tax	1.6	0.9	2.5	0.8	0.5	1.3	0.7	0.4	1.1	3.2	1.8	4.9
Total Perm Diff Tax	3.9	1.8	5.7	1.9	1.1	3.0	1.7	0.9	2.6	7.5	3.8	11.4
Timing Difference	0.0	28.5	28.5	0.0	10.3	10.3	9.9	31.0	40.9	9.9	69.8	
RA Timing Diff	2.2											
Total Timing Diff	0.0	28.5		0.0	10.3		9.9	31.0		9.9	69.8	
Tax on Timing Diff	0.0	4.4	4.4	0.0	1.6	1.6	2.8	4.8	7.6	2.8	10.8	13.6
Tax on Timing Tax	2.2	1.2	3.4	0.8	0.4	1.2	3.8	2.1	5.8	6.7	3.7	10.5
Total Timing Tax	2.2	5.6	7.8	0.8	2.0	2.8	6.5	6.9	13.4	9.5	14.5	24.1
Lge Corp Tax (LCT)			3.7			1.4			2.0			7.1
Tax on LCT	1.8	1.0	2.8	0.7	0.4	1.1	1.0	0.5	1.5	3.5	1.9	5.5
Total LCT	1.8	1.0	6.5	0.7	0.4	2.5	1.0	0.5	3.5	3.5	1.9	12.6
Fixed Tax Adj	**7.9**	**8.5**	**20.1**	**3.4**	**3.5**	**8.3**	**9.2**	**8.4**	**19.6**	**20.5**	**20.3**	**48.0**
Total Income Tax	**46.5**	**29.8**	**80.0**	**16.4**	**10.6**	**28.4**	**21.0**	**14.9**	**37.9**	**83.8**	**55.4**	**146.3**

PARTIES PARTICIPATING IN THE PROCEEDING

PRINCIPALS AND REPRESENTATIVES

EPCOR Transmission Inc. (EPTI) and EPCOR Generation Inc. (EPGI)	Mr. D. R. Wright, Q.C. Mr. J. M. Liteplo
ATCO Electric Ltd. (AE)	Mr. L. G. Keough
TransAlta Utilities Corporation (TransAlta)	Mr. J. J. Marshall, Q.C. Ms. B. Ho Mr. C. L. Clarke
ENMAX Utilities	Mr. R. B. Brander Ms. P. Quinton-Campbell
ESBI Alberta Limited (EAL or ESBI)	Mr. D. A. Holgate
Cost of Capital Investors (COCI)	Mr. C. K. Yates
Industrial Power Consumers Association of Alberta (IPCAA)	Mr. D. E. Crowther
Municipal Intervenor Group (MI)	Mr. J. A. Bryan, Q.C. Mr. C. R. McCreary
British Columbia Power Exchange Corporation and B.C. Power and Hydro Authority (POWEREX)	Ms. C. A. Low
Cities of Lethbridge (Lethbridge) and Red Deer (Red Deer)(LE/RD)	Ms. P. A. Smith, Q.C.
Alberta Cogenerators Council (ACC)	Mr. R. C. Secord
Public Institutional Consumers of Alberta (PICA)	Ms. N. J. McKenzie Mr. R. Retnanandan
Alberta Association of Municipal Districts and Counties (AAMDC)	Mr. J. J. Burgess, Q.C.
Alberta Federation of REAs Ltd. (REA)	Mr. K. L. Sisson, Q.C.

Consumers' Coalition of Alberta (CCA)	Mr. J. A. Wachowich
Alberta Irrigation Projects Association (AIPA)	Mr. J. H. Unryn
Independent Power Producers Society of Alberta (IPPSA) and Senior Petroleum Producers Association (SPPA)	Mr. L. L. Manning
First Nations	Mr. J. Graves Mr. A. O. Ackroyd

WITNESSES

EPCOR Generation Inc. and EPCOR Transmission Inc.

General Panel
Dr. David Lewin
Mr. Brian Vaasjo
Mr. Doug Topping
Dr. Guy Bridgeman
Dr. Asish DeSarkar
Mr. Lee Millar
Dr. Ronald E. White

Rate of Return
Dr. Bob Evans

Capital Structure
Dr. Bob Evans

Capital Markets
Ms. Terry McLeod

TransAlta Utilities Corporation

Operations
Mr. Dick Way
Mr. Wolfgang Janke
Mr. Paul Clark
Mr. Jim Benedict
Mr. Bob Low
Mr. Bill Hosie
Mr. Neil Millar
Mr. Yves Tremblay

Financing
Mr. Dick Way
Mr. Bill Veres
Mr. Marvin Waiand
Mr. Barney Woo

Capital Markets
Mr. Richard D. Falconer

Rate of Return
Dr. A. Larry Kolbe
Dr. Michael J. Vilbert

ATCO Electric Ltd.

Mr. Dick Walthall
Mr. Brian Bale
Mr. Ladis Vegh

ENMAX

Mr. Hugh W. Johnson

Depreciation
Mr. William M. Stout
Mr. Larry E. Kennedy

FIRM Customers

Mr. William B. Marcus

Depreciation
Mr. Jacob Pous

Cost of Capital Intervenors Panel

Rate of Return
Dr. William R. Waters
Dr. Ralph A. Winter

IPCAA

Drazen Consulting Group
Mr. Mark Drazen
Mr. Ron Mikkelsen
Ms. Billie LaConte
Ms. Lynn Pearson
Mr. Dan Macnamara
Mr. Richard Gallant

ORDER/ DECISION/ REPORT NO.	DATE	PARTICULARS
E75069	14 August 1975	Calgary Power Ltd. (now TransAlta Utilities Corporation) (Decision – Revision of Rates)
E78100	30 June 1978	Alberta Cost of Service Inquiry (Report – Natural Gas – Order in Council 1016/76 dated 21 September 1976)
E81014	11 February 1981	Canadian Western Natural Gas Company Limited (Decision – General Rate Application)
E83065	9 May 1983	Canadian Western Natural Gas Company Limited (Decision – General Rate Application – Phase I)
E83074	14 June 1983	Northwestern Utilities Limited (Decision – General Rate Application)
E83130	10 November 1983	City of Edmonton and Alberta Electric Energy Marketing Agency (Decision – Rate setting)
E85129	25 November 1985	TransAlta Utilities Corporation (Decision – 1985/1986 General Rate Application – Phase I)
C85250	20 December 1985	Canadian Western Natural Gas Company Limited (Decision – 1985/1986 General Rate Application – Phase I)
E87002	6 February 1987	Northwestern Utilities Limited (Decision – General Rate Application)
E87100	18 December 1987	Alberta Power Limited, Edmonton Power and TransAlta Utilities Corporation (Decision – 1986 EEMA Adjustment)
E88018	18 March 1988	Northwestern Utilities Limited (Decision – 1987/1988 General Rate Application – Phase I)

ORDER/ DECISION/ REPORT NO.	DATE	PARTICULARS
E89091	15 December 1989	TransAlta Utilities Corporation (Decision – 1988/1989/1990 General Rate Application – Phase I)
E91093	16 December 1991	TransAlta Utilities Corporation (Decision – 1991/1992 General Rate Application – Phase I)
E91094	22 November 1991	Northwestern Utilities Limited (Amending Order – Amending E91044 re 1991/1992 General Rate Application.
E92039	18 May 1992	Alberta Power Limited (Decision – 1992 General Rate Application – Phase I)
E92111	9 December 1992	Alberta Power Limited, Edmonton Power and TransAlta Utilities Corporation (Decision – 1991 EEMA Adjustment and 1993 EEMA Forecast)
E93004	8 February 1993	Canadian Western Natural Gas Company Limited (Decision – 1992/1993 General Rate Application – Phase I)
E93053	7 October 1993	TransAlta Utilities Corporation (Decision – 1993 Expedited Application)
E93060	20 August 1993	NOVA Corporation of Alberta (Decision – Complaint by Canadian Association of Petroleum Producers)
E93094	10 December 1993	Alberta Power Limited, Edmonton Power and TransAlta Utilities Corporation (Decision – 1994 EEMA Forecast)
HE 9308	13 October 1993	Edmonton Power Inc. (Approval – To discontinue the operation, dismantle and remove the Rossdale Low Pressure Plant.
E94001	21 January 1994	Northwestern Utilities Limited (Decision – 1993/1994 General Rate Application – Phase I)

ORDER/ DECISION/ REPORT NO.	DATE	PARTICULARS
E94095	9 December 1994	Alberta Power Limited, Edmonton Power and TransAlta Utilities Corporation (Decision – 1995 EEMA Forecast)
U97065	31 October 1997	Alberta Power Limited, Edmonton Power Inc., TransAlta Utilities Corporation and Grid Company of Alberta (Decision –1996 Electric Tariff Application)
U98124	12 August 1998	TransAlta Utilities Corporation (Order – Investigation of 1995 Rates)
U99035	10 August 1999	TransAlta Utilities Corporation (Decision – 1996 Electric Tariff – Phase II)
U99046	10 May 1999	ATCO Electric Ltd. (Decision – 1999/2000 Tariff Application – Phase I – Negotiated Settlement)

ACTS AND REGULATIONS

ACT	AR #	REGULATION
Alberta Energy and Utilities Board Act		
Arbitration Act		
Electric Utilities Act	284/95	Temporary Suspension Regulation
	168/98	Distribution Regulation
	278/98	Market Surveillance Report
	72/99	Generating Units Regulation
	169/99	Balancing Pool Regulation
	170/99	Power Purchase Arrangement Regulation
	180/99	Direct Sales Regulation
Fisheries Act (Federal)		
Income Tax Act		
Judgment Interest Act		
Municipal Government Act	365/94	Standards of Assessment Regulation
	367/94	Assessable Property Regulation
Public Utilities Board Act		
Small Power Research and Development Act	358/94	Revenue Adjustment Regulation
Utility Companies Income Tax Rebates Act		

ABBREVIATIONS

AAMDC	Alberta Association of Municipal Districts and Counties
ACC	Alberta Cogenerators Council
ACF	Available Capability Factor
AE	ATCO Electric Ltd. (formerly Alberta Power Limited)
AEC	Alberta Energy Company
AEUB Act	*Alberta Energy and Utilities Board Act*
AFE	Authorization for Expenditure
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
AHA	Alberta Healthcare Association
AIES	Alberta Interconnected Electric System
AIPA	Alberta Irrigation Projects Association
AIS	Alberta Interconnected System
ALC	Air Liquide Canada Inc.
ANEC	Available Net Energy Capability
APL	Alberta Power Limited (now ATCO Electric Ltd.)
AR	Alberta Regulation
ARP	Aggregate Reservation Price
ATWACC	After Tax Weighted Average Cost of Capital
$ATWACC_{BV}$	An ATWACC determined using weighted **book** capitalization ratios

$ATWACC_{MV}$	An ATWACC determined using weighted **market** capitalization ratios
BISI	Business Integrated Solutions Initiatives
Board or AEUB	Alberta Energy and Utilities Board
Boyd	John T. Boyd Company
BP	Balancing Pool
Calgary	City of Calgary
CAPM	Capital Asset Pricing Model
$Capital_{BV}$	Capital determined using weighted **book** capitalization ratios
CBIS	Common Business Information System
CBRS	Canadian Bond Rating Service
CCA	Consumers' Coalition of Alberta
CCES	City of Calgary Electric System
CCES Report	City of Calgary Electric System Report
CICA	Canadian Institute of Chartered Accountants
CMH	City of Medicine Hat
COCI or CCI	Cost of Capital Intervenors – ENMAX Utilities, ESBI Alberta Limited, Industrial Power Consumers Association of Alberta, City of Lethbridge and City of Red Deer
CRA	Charles River Associates
CUBIS	Customer Utility Billing and Information System
CWIP	Construction Work in Progress

CWNG	Canadian Western Natural Gas Company Limited
DAT	Direct Access Tariff
DB	Defined Benefit
DBRS	Dominion Bond Rating Service
DC	Defined Contribution
DCF	Discounted Cash Flow
DCGI	Drazen Consulting Group, Inc.
DCS	Distributed Control System
DISCO	Distribution Company (Owner of an "entitled electric distribution system" under the *Electric Utilities Act*, S.A. 1995)
DRD	Alberta Department of Resource Development
EAL	ESBI Alberta Limited – the Transmission Administrator
ECAPM	Empirical Capital Asset Pricing Model
ECR	Emergency Capability Rating
EEMA	Electric Energy Marketing Agency
EMPAC	Work Management System
ENCORE	Encore Energy Solutions LP
ENMAX	ENMAX Utilities
ENPRO	Production Modelling Computer Program
EPCI	EPCOR Customers Services Inc.
EPCOR	EPCOR Corporation

EPDI	EPCOR Distribution Inc.
EPGI	EPCOR Generation Inc.
EPI	Edmonton Power Inc.
EPTI	EPCOR Transmission Inc.
ERCB	**Energy Resources Conservation Board**
EU Act	***Electric Utilities Act***
EUPC	**Electric Utility Planning Council**
FCL	**Fording Coal Limited**
FIRM Customers	Alberta Association of Municipal Districts and Counties, Alberta Federation of REAs Ltd., Alberta Irrigation Projects Association, Consumers' Coalition of Alberta, Municipal Intervenors, Public Institutional Consumers of Alberta and Senior Petroleum Producers Association.
FMOR	Forced plus Maintenance Outage Rate
FTE	Full Time Equivalent
G&A	General and Administration
GENCO	Generation Company
GME	General Mine Expense
GRA	General Rate Application
Gridco	Grid Company of Alberta
GST	Goods and Services Tax
GTA	General Tariff Application

GUR	Generating Units Regulation (AR 72/99 EU Act)
HP	High Pressure
HRSC	High River Service Centre
IAT	Independent Assessment Team
IP	Intermediate Pressure
IPP	Independent Power Producers
IPCAA	Industrial Power Consumers Association of Alberta
IPPSA	Independent Power Producers Society of Alberta
IS	Information Services
IT	Information Technology
IVR	Interactive Voice Response
LE/RD	Cities of Lethbridge and Red Deer
Lethbridge	City of Lethbridge
LP	Low Pressure
M&E	Machinery and Equipment
MCR	**Maximum Continuous Rating**
MG Act	***Municipal Government Act***
MI	Municipal Intervenors
Minister	Minister of Alberta Department of Resource Development
MRM	Minimum Return Margin
mty	Million tonnes per year

NATP	Normalized All Taxes Paid
NDT	Normalized Deferred Tax
NEB	National Energy Board
NERA	National Economic Research Associates
NFR	Non-Farm Rural
NLP	Newfoundland Light & Power
NO_x	Nitrous oxide
NPV	Net Present Value
NWC	Necessary Working Capital
NYMEX	New York Mercantile Exchange
O&M	Operating and Maintenance
PHFFU	Plant Held for Future Use
PICA	Public Institutional Consumers of Alberta
PMO	Project Management Office
PNG	Pacific Northern Gas
Power Pool	Power Pool of Alberta
POWEREX	British Columbia Power Exchange Corporation and BC Power and Hydro Authority
PPA	Power Purchase Arrangements
PROMOD	Production Modelling Computer Program
PROSYM	Production Modelling Computer Program

PUB Act	**Public Utilities Board Act**
PWC	PricewaterhouseCoopers
RAR	Revenue Adjustment Regulation (AR 358/94 SPRD Act)
RAS	Remedial Action Scheme
RCM	Reliability Centered Maintenance
REA	Alberta Federation of REAs Ltd.
Red Deer	City of Red Deer
Reserve	AE's generation portion of its Reserve for Injuries and Damages
RFP	Request for proposal
ROE	Return on Equity
Rossdale	Rossdale Generating Plant
SaskPower	Saskatchewan Power Corporation
SCADA	Supervisory Control and Data Acquisition
Settlement	Negotiated Settlement Agreement
SIR	Self-Insurance Reserve
SMP	System Marginal Price
SPP	Small Power Producers
SPPA	Senior Petroleum Producers Association
SPRD Act	*Small Power Research and Development Act*
T&C	Terms and Conditions
TA	Transmission Administrator

TAOP	Transmission Administrator Operating Procedures
TCE	TransCanada Energy Ltd.
TEM	TransAlta Energy Marketing Corporation
TFO	Transmission Facility Owner(s)
TPG	Transmission Planning Guidelines
TransAlta, TAU or TransAlta Utilities	TransAlta Utilities Corporation
TSE	Toronto Stock Exchange
TSR	Temporary Suspension Regulation (AR 284/95 EU Act)
UCC	Undepreciated Capital Cost
UOA	Unit Obligation Amounts
UOP	Unit Obligation Price
UOV	Unit Obligation Value
VARS	Voltage Ampere Reactive
WACC	Weighted Average Cost of Capital
WSCC	Western Systems Coordinating Council